UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

New Source Performance Standards	)	
for Greenhouse Gas Emissions	)	
From New, Modified, and	)	**Docket No. EPA-HQ-OAR-2023-0072**
Reconstructed Fossil Fuel-Fired	)	
Electric Generating Units; Emission	)	*Via regulations.gov*
Guidelines for Greenhouse Gas	)	*August 8, 2023*
Emissions From Existing Fossil	)	
Fuel-Fired Electric Generating	)	
Units; and Repeal of the Affordable	)	
Clean Energy Rule	)	

We submit these comments on behalf of Clean Air Task Force, and Natural Resources Defense Council (together, "Commenters"), joined by The Nature Conservancy. Commenters are nonprofit organizations with decades of legal, technical and policy expertise on energy, environmental, and public health issues.

List of Frequently Used Acronyms and Abbreviations

ACE - Affordable Clean Energy Rule
ACO - Administrative Compliance Order
AEO - Annual Energy Outlook
ATB - Annual Technology Baseline
ATP - Andover Technology Partners
BSER - Best System of Emission Reduction
BTS - U.S. Department of Transportation Bureau of Transportation Statistics
CAIR - Clean Air Interstate Rule
CATF - Clean Air Task Force
CCS - Carbon Capture and Sequestration
CEMS - Continuous Emissions Monitoring System
CO_2 - Carbon Dioxide
CPP - Clean Power Plan
CT - Combustion Turbine
DOE - U.S. Department of Energy
EGU - Electric Generating Unit
EIA - U.S. Energy Information Administration
EOR - Enhanced Oil Recovery
EPA - U.S. Environmental Protection Agency
EPAct05 - Energy Policy Act of 2005
EPRI - Electric Power Research Institute
ERM - Environmental Resources Management, Inc.
FEED - Front-End Engineering Design
FGD - Flue Gas Desulfurization
GE – General Electric
GHG - Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GREET - Greenhouse Gases, Regulated Emissions, and Energy use in Transportation
HRI - Heat Rate Improvements
H_2 - Hydrogen
IRA - Inflation Reduction Act
IIJA - Infrastructure Investment and Jobs Act, also known as the Bipartisan Infrastructure Law (BIL)
IPM - Integrated Planning Model
IPCC - Intergovernmental Panel on Climate Change
IRP - Integrated Resource Plan
[K/M/G/T]W[h] - [Kilo/Mega/Giga/Tera]Watt-[hour]
LCA - Lifecycle Analysis
LCOE – Levelized Cost of Electricity
MATS - Mercury and Air Toxics Standards
[M/G]T - [Mega/Giga]ton (metric unless otherwise specified)
MHI - Mitsubishi Heavy Industries, Ltd.
MMBTU – million British thermal units
MMT - million metric ton
NCA4 - The Fourth National Climate Assessment
NERC - North American Electric Reliability Corporation
NETL - National Energy Technology Laboratory
NGCC - Natural Gas Combined Cycle
NO_x - Nitrogen Oxides
NOAA - National Oceanic and Atmospheric Administration
NRDC - Natural Resources Defense Council
NREL - National Renewable Energy Laboratory
NSR - New Source Review
NSPS - New Source Performance Standards
OEMS - Original Equipment Manufacturers
PHMSA - U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
$PM_{2.5}$ - Fine Particulate Matter
PSD - Prevention of Significant Deterioration

RDF- Retrofit Difficulty Factor
ReEDS - Regional Energy Deployment System
RIA - Regulatory Impact Analysis
RULOF - Remaining Useful Life and Other Factors
SCR - Selective Catalytic Reduction
SMR – Steam Methane Reforming
SO_2 - Sulfur Dioxide
S&P – Standard & Poor's
TSD - Technical Support Document
WLE - Wet low-emission

I. Introduction and Summary of Recommendations

The U.S. Environmental Protection Agency (EPA) first requested comment on how to control greenhouse gases (GHGs) from electric generating units (EGUs) under Clean Air Act Section 111 almost exactly fifteen years ago.[1] Now, after court decisions and new congressional action, EPA has proposed standards to curb GHG emissions from three groups of EGUs: existing coal-fired units and new and existing gas-fired units.[2] These Joint Comments from Clean Air Task Force (CATF) and Natural Resources Defense Council (NRDC), joined by the Nature Conservancy, support the framework EPA has proposed and recommend further improvements in response to EPA's requests for comment.

The urgency of the climate crisis—underlined by the record-breaking heat and catastrophic storms experienced world-wide this summer—warrants the fastest possible reduction in GHGs from power plants, the nation's second largest source of heat-trapping pollution. EPA has a long-standing legal obligation to curb power plants' carbon dioxide (CO_2) pollution under Section 111 of the Clean Air Act.

In *West Virginia v. EPA*, the Supreme Court delineated a clear path forward for controlling power plant emissions under this provision.[3] Congress subsequently enacted the Inflation Reduction Act (IRA), the nation's largest investment in climate and clean energy.[4] The IRA expressly and clearly reiterates EPA's obligation to act by directing the agency to use its Clean Air Act authority to set GHG emission standards for EGUs taking those new incentives into account. Given the climate crisis, the incentives Congress has provided, and the task Congress has assigned to EPA under the Clean Air Act, the time is now for EPA to set standards that will achieve and ensure swift climate pollution reductions from the EGU fleet.

The fundamental structure of the proposal is strong, consistent with *West Virginia* and the IRA, and well-aligned with the evolving roles that different fossil fuel-fired EGUs are playing in the provision of electricity. In determining the best systems of emission reduction for various subcategories of EGUs, EPA has properly focused on traditional pollution controls like cleaner fuels, efficient design and operation, and end-of-the stack emission equipment of the kind that the Supreme Court spoke favorably of last year. The proposal provides generous lead times for implementation and compliance and will not cause reliability problems when finalized. Considering the magnitude of the changes underway in the power sector's business-as-usual trajectory, as well as the availability of IRA incentives, the proposed standards are modest and incremental. The Clean Air Act authorizes, indeed directs, EPA to do more. Accordingly, CATF and NRDC offer specific comments to strengthen the rules. We also highlight two specific concerns, the first regarding the potential for localized pollution increases and community protection, and the second regarding appropriate use of hydrogen.

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[1] 73 Fed. Reg. 44354 (July 30, 2008).
[2] 88 Fed. Reg. 33240 (May 23, 2023). New coal and gas-fired units are already subject to a standard. 80 Fed. Reg. 64510 (Oct. 23, 2015).
[3] 142 S. Ct. 2587 (2022).
[4] Pub. L. No. 117-169, 136 Stat. 1818 (2022).

A. Existing Coal-Fired EGUs

Aging and increasingly uneconomic coal-fired EGUs are retiring in response to market forces and the incentives provided by Congress in the IRA and the Infrastructure Investment and Jobs Act (IIJA).[5] The proposal is designed to align with industry plans to retire coal units by creating subcategories setting more lenient emission limits for units retiring in the near- and mid-term. These emission limits enable operators to comply without making significant further pollution control investments in those facilities.

At the same time, recognizing that some companies intend to continue operating coal-fired EGUs indefinitely, the proposal ensures that GHG emissions of those units will be well controlled starting in 2030, with standards based on the emission reductions achievable through carbon capture and sequestration (CCS).

We support EPA's determination that CCS is adequately demonstrated and cost-effective for existing coal-fired EGUs intended to run the longest and hardest, especially taking into account incentives provided by the IRA. CCS can remove nearly all carbon emissions from a power plant at very reasonable cost.

It is also cost-effective to tighten the proposed timelines and strengthen requirements for coal-fired units that, though shorter lived, will otherwise emit large amounts of CO_2.

Considering the IRA incentives and other factors, NRDC and CATF urge EPA to tighten the proposal for existing coal-fired units in these ways:

- Advance the date for the subcategory of long-lived coal units from 2040 to ***2038.*** The eight-year period from 2030 to 2038 is sufficient to recover the costs of installing CCS in 2030, particularly after accounting for the large incentives in the IRA.
- For the subcategory of units retiring after 2030 but before 2038 and running at low-load (less than 20 percent capacity factor), the emission limit should be based on maintaining historical emission rates.
- For the subcategory of units retiring within this timeframe but running more than 20 percent of capacity, the emission limit should be based on 40 percent co-firing of gas by heat input.

B. New Gas-Fired EGUs

The proposal recognizes the evolving roles that new methane gas-fired EGUs are playing as the electric grid becomes increasingly powered by renewable energy in response to market trends and IRA/IIJA incentives. EPA has proposed standards for different subcategories of new gas-fired EGUs based on their level of use. The proposal aims to achieve significant pollution reductions beginning in 2035 from new gas plants that operate the most while allowing less utilized units to provide critical reliability support to renewable generation.

[5] Pub. L. No. 117-58, 135 Stat. 429 (2021).

CATF and NRDC analysis, however, shows that the emission limits and timetables can be cost-effectively advanced. We urge EPA to tighten the proposal for new gas units in the following ways:

- For baseload new gas-fired EGUs, lower the applicable capacity factor to 40 percent and set the emission limit based on 90 percent post-combustion capture and sequestration starting in 2035.
- For the intermediate load subcategory, lower the capacity factor limit from about 50 percent to 40 percent. Set the first phase emission limits based on efficient operation of the type of combustion unit (setting separate standards for simple and combined cycle units).[6] Set the second phase emission limit based on 30 percent low-GHG hydrogen co-firing, ramping up to 90 percent low-GHG hydrogen co-firing in the third phase.
- Lower the capacity factor limit for the low-load subcategory to no higher than 15 percent.[7] Set the emission limit based on 30 percent low-GHG hydrogen starting in phase 2.[8]

C. Existing Gas-Fired EGUs

Existing gas EGUs account for 40 percent of current electricity production and 43 percent of the sector's current CO_2 emissions. It is essential to cover existing gas units within this rulemaking in order to reduce the emissions of high emitters and prevent the emissions leakage that would occur if emissions were limited only from existing coal and new gas EGUs. Recognizing that many existing gas EGUs will be used through the next decade, EPA has proposed emission limits based on CCS or hydrogen co-firing for a subset of large, heavily-used existing units.

CATF and NRDC support coverage of existing gas units while recommending changes to the definition of the covered subcategory:

- Define the subcategory of existing gas units subject to a CCS-based emission limit on a plant-wide, rather than a unit, basis. Many high-emitting gas plants are composed of multiple units. Because multiple co-located EGUs can be connected to a single CCS unit, applying CCS on this plant-wide basis makes the most economic and logistical sense. Commenters recommend CCS-based emission limits apply to EGUs located in plants with total gas-fired capacity above 600 megawatts (MW) and a plant-wide capacity factor for gas-fired units of more than 45 percent.

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[6] Commenters also support the recommendations in the Sierra Club's comments, at Sec. III. A, for BSER for phase 1 standards for intermediate-load units.
[7] Commenters have modeled a case where the upper limit for the low-load subcategory is reduced to 15 percent. Commenters also support reducing the upper limit further to 5 to 8 percent as proposed by the Sierra Club in its comments, at Sec. III.B..
[8] As summarized below and elaborated in Appendix B, Sec. II, Commenters have significant concerns about using energy-intensive hydrogen for power generation instead of more difficult to decarbonize industries, and we provide detailed definitions necessary to assure that hydrogen is in fact low-GHG, see Appendix B. Sec. VI.

- Make a firm commitment to appropriately regulate the CO_2 emissions of the remainder of the existing gas fleet as expeditiously as possible.

D. Potential Localized Pollution Increases

While EPA projects large overall reductions in CO_2 and in health-damaging pollutants such as sulfur dioxide (SO_2), fine particles ($PM_{2.5}$), and nitrogen oxides (NO_x), the agency's modeling identifies the potential for some localized pollution increases. We agree with groups representing environmental justice communities that are already overburdened by the cumulative pollution from power plants and other sources that this potential is a serious concern and outline additional actions for EPA to take to avoid these impacts. We also support vigorous action across EPA's authorities and by other agencies to assure the safe operation of related facilities, such as CO_2 pipelines (which fall in the jurisdiction of both the Pipeline and Hazardous Materials Safety Administration (PHMSA) and EPA) and CO_2 sequestration wells (which fall under EPA's jurisdiction).[9]

E. Hydrogen

Hydrogen is an energy-intensive fuel that is best used in—and should be prioritized for—applications that are the hardest to decarbonize (e.g., certain heavy industries). Its use in this rule should be focused only where there is not a better alternative, and only where it can be assured that hydrogen has been produced with truly low-GHG emissions. Thus, we recommend that EPA not define hydrogen co-firing as a best system of emission reduction (BSER) for baseload gas-fired EGUs, because CCS is more cost-effective. While hydrogen co-firing is more cost-effective for gas-fired EGUs operating at low and intermediate load, the emissions benefit must not be lost by using hydrogen produced with high GHG emissions. To assure that the emission reduction benefits of burning hydrogen in EGUs are not lost by production-related emissions, EPA must require that any hydrogen used for compliance be low-GHG hydrogen. In addition, technical feasibility does not always translate to reasonable infrastructure requirements or system-wide costs, and low-GHG hydrogen should only be used where truly needed in the power sector.

F. The Power Industry Can Meet These Standards

The electric power industry has a long history of objecting to new pollution control requirements as they are proposed, but then outperforming those requirements once they are set. Many companies have set and are expected to meet corporate decarbonization commitments that exceed or are close to what this proposal would require, or indeed what CATF and NRDC recommend in the way of improvements. Our comments review past examples that demonstrate the industry's ability to move quickly once market incentives and regulatory requirements are clear, unleashing faster deployment and further cost declines that industry comments claimed were unreachable. The current framework of market trends and governmental incentives could not be more favorable for fossil fuel-fired EGUs to significantly reduce their emissions, especially given the ample lead times and flexible regulatory structure in this proposal.

[9] NRDC and others have urged PHMSA to accelerate its rulemaking to strengthen CO_2 pipeline safety requirements. Letter from Bill Caram, Exec. Dir., Pipeline Safety Trust, to Pete Buttigieg, Sec'y, DOT (May 01, 2023), https://pstrust.org/wp-content/uploads/2023/08/DOT-CO2-Pipeline-Safety-Letter.pdf.

Operators have additional flexibility since standards under Section 111 are performance standards. It is entirely the choice of states and owner/operators whether to meet standards by adopting EPA's reference technology or taking a different path. Given market forces, industry trends, and the IRA/IIJA investment incentives, many EGU owners and operators are choosing to replace fossil-fired generators with less costly, clean generation resources. As mentioned above, EPA's proposed more lenient standards for limited-life/limited-use subcategories accommodates these preferences. Others will choose to operate their units in conformity with these standards. That is consistent with Congress's clear incentives and expectations, as consistently expressed for more than 50 years, most recently in the IRA enacted in 2022.

II. Climate Change & Power Sector Contribution

Elevated concentrations of GHGs and other pollutants in the atmosphere are transforming the climate at a rate and scale that threaten the natural environment and human civilizations. The effects of such historical pollutants have already started appearing. Global average temperature was higher by about 1.1 degrees Celsius during the 2011-2020 decade compared to the late 19th century.[10] Indeed, according to multiple datasets, the years between 2015 and 2021 were the seven warmest years in surface temperature records going back to 1880.[11]

The increased concentrations of pollutants and resulting warming have led to disruption in a variety of forms. Global average sea level rose by about 8 inches from 1901 to 2018,[12] which has heightened coastal flooding and erosion impacts.[13] Acidification of the ocean in recent decades due to higher levels of CO_2 negatively impacts many marine organisms.[14] The Intergovernmental Panel on Climate Change (IPCC) found that global temperature warming has caused irreversible losses in terrestrial, freshwater, and ocean marine ecosystems.[15]

Climate change has increased the frequency and intensity of heatwaves, heavy precipitation, and droughts.[16] In the United States specifically, heavy precipitation events have elevated in the East[17] while drought has increased in the West[18] along with larger, more intense wildfires.[19] Air pollutants from wildfires, as well as from fossil fuel-fired EGUs, significantly degrade the quality of the air that we breathe, resulting in increased health risks.[20] This summer alone has

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[10] IPCC, *Climate Change 2021: The Physical Science Basis*, at 5 (2021), https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_FullReport_small.pdf.
[11] Jessica Blunden & Tim Boyer, *State of the Climate in 2021*, at S27-28 (2022), https://ametsoc.net/sotc2021/StateoftheClimate2021_lowres.pdf.
[12] *See* IPCC, *Climate Change 2021*, *supra* note 10, at 5.
[13] 88 Fed. Reg. at 33251.
[14] *See* IPCC, *Climate Change 2021*, *supra* note 10, at 76.
[15] 88 Fed. Reg. at 33251 (citing IPCC, *Climate Change 2022: Impacts, Adaptation, and Vulnerability*, at 3-33 (2022), https://report.ipcc.ch/ar6/wg2/IPCC_AR6_WGII_FullReport.pdf.
[16] IPCC, *Climate Change 2021*, *supra* note 10, at 8.
[17] *See* EPA, *U.S. and Global Precipitation*, Climate Change Indicators (July 21, 2023), https://www.epa.gov/climate-indicators/climate-change-indicators-us-and-global-precipitation.
[18] *See* EPA, *Drought*, Climate Change Indicators (July 21, 2023), https://www.epa.gov/climate-indicators/climate-change-indicators-drought.
[19] *See* EPA, *Wildfires*, Climate Change Indicators (July 21, 2023), https://www.epa.gov/climate-indicators/climate-change-indicators-wildfires.
[20] *See* 88 Fed. Reg. at 33250-51.

seen numerous climate-escalated weather events. In one week, ocean temperatures topped 100 degrees Fahrenheit off the coast of Florida, a rare tornado touched down in Delaware, and catastrophic flooding was observed in both Vermont and the Hudson Valley.[21] In July, smoke from rampant Canadian wildfires enveloped numerous cities, a dangerous heat wave hit both Texas and Oklahoma, and heavy rain flooded areas of Chicago.[22] Many similar heatwaves, wildfires, storms, and flooding are occurring around the world. Scientists have observed that July 3 to 5, 2023 were likely the hottest three days in Earth's modern history.[23]

According to the National Oceanic and Atmospheric Administration (NOAA), natural disasters cost the United States an average of 21.2 billion dollars per year in the 1980s.[24] That figure grew to a whopping 150.6 billion dollars per year for the period between 2020 and 2022.[25] Whereas the average year in the 1980s saw roughly 3.3 disasters that cost more than one billion dollars, the past three years have averaged about 20 billion-dollar disasters per year.[26]

In communities across the United States, the health and safety impacts of these extreme weather events,[27] and other climate impacts, all disproportionately fall on low-income communities and communities of color, and climate change will likely worsen these disparities.[28]

Clearly, the effects of our warming climate are already upon us, and yet, future projections are even more severe. Additional warming will increase the magnitude of changes we have already begun to encounter and could lead to a climate unlike anything humans have ever experienced.[29] The Fourth National Climate Assessment (NCA4) found that it is very likely that by mid-century, the Arctic Ocean will be almost entirely free of late-summer sea ice.[30] With an additional 1 degree Celsius in warming, coral reefs will be at risk for almost complete losses.[31] Climate change is expected to cause more intense hurricanes as well as increase the frequency and intensity of other types of storms.[32] The NCA4 also found that climate change can increase

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[21] David Gelles, *Climate Disasters Daily? Welcome to the 'New Normal,'* New York Times (July 10, 2023), https://www.nytimes.com/2023/07/10/climate/climate-change-extreme-weather.html.
[22] *Id.*
[23] Brad Plumer & Elena Shao, *Heat Records Are Broken Around the Globe as Earth Warms, Fast*, New York Times (July 6, 2023), https://www.nytimes.com/2023/07/06/climate/climate-change-record-heat.html.
[24] NOAA, Nat'l Ctrs. for Env't Info., *Billion-Dollar Weather and Climate Disasters*, https://www.ncei.noaa.gov/access/billions/ (last visited July 26, 2023) (dollar values adjusted to 2023 CPI levels).
[25] *Id.*
[26] *Id*.
[27] Corey Williams & Mike Householder, *Smoke from Canada wildfires is increasing health risks in Black and poorer US communities,* Associated Press (June 28, 2023), https://apnews.com/article/canada-wildfire-smoke-832caae1e622b10766521598fccc6e63.
[28] EPA, *Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts* (2021), https://www.epa.gov/cira/social-vulnerability-report; Alique Berberian et al., *Racial Disparities in Climate Change-Related Health Effects in the United States,* 9 Current Env't Health Rep. 451 (2022), https://doi.org/10.1007/s40572-022-00360-w.
[29] 88 Fed. Reg. at 33250.
[30] 88 Fed. Reg. at 33251 (citing U.S. Global Change Research Program (USGCRP), *Volume II: Impacts, Risks, and Adaptation in the United States* in *Fourth National Climate Assessment*, at 74 (2018), https://nca2018.globalchange.gov/downloads/NCA4_2018_FullReport.pdf).
[31] *See* IPCC, *Global Warming of 1.5° Celsius*, at 8 (2019), https://www.ipcc.ch/site/assets/uploads/sites/2/2022/06/SR15_Full_Report_LR.pdf.
[32] 88 Fed. Reg. at 33249.

risks to national security, both through impacts to military infrastructure as well as by affecting factors such as food and water availability that can lead to increased conflicts.[33] As EPA recognizes, the increasing concentrations of GHGs in the atmosphere pose serious and life-threatening risks to public health and welfare.[34]

There is a stronger-than-ever global scientific consensus that human actions, notably burning fossil fuels without controls, have caused climate change. The IPCC, comprised of 195 government members tasked with assessing climate change science for the United Nations,[35] found unequivocally that human activity has warmed the atmosphere, ocean, and land since the pre-industrial period.[36] The burning of fossil fuels has been the largest contributor to global climate change by far, accounting for over 75 percent of GHG emissions.[37]

The power sector has historically been a major source of fossil fuel burning and related GHG emissions. In 2021, the power sector was the second largest contributor to U.S. GHG emissions, emitting 25 percent of the total.[38] This sector contributes an even higher percentage to CO_2 emissions specifically, accounting for about 31 percent of U.S. emissions in 2021.[39] Coal combustion is especially carbon-intensive. In 2021, despite representing only 23 percent of the electricity generated in the United States, coal use accounted for 59 percent of carbon emissions from the power sector.[40]

Finalizing this rule is also expected to deliver significant human health benefits, both as a result of reducing GHG emissions that otherwise would contribute to climate change and co-benefits from reducing criteria pollutant emissions. EPA estimates the proposal could produce up to $92 *billion* in monetized climate benefits in present value terms between 2028 and 2042,[41] which is likely an underestimate.[42] In 2030 alone, the benefits of reducing CO_2 emissions range from $1.7 billion to $16 billion (2019 dollars, or between $2 to $19 billion in 2022 dollars). And EPA estimates that its proposal will save up to 1,200 lives in the year 2030 alone as a result of reduced particulate exposures.[43] Commenters' modeling of recommended improvements (the Preferred Policy Case, as described in more detail in Section VI.D *infra*) shows that the emission reductions and consequent benefits will likely be greater than EPA presents in the RIA. For

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[33] *Id*. at 33251-52 (citing USGCRP, *Impacts* at 606).
[34] *Id*. at 33243.
[35] IPCC, *About the IPCC*, https://www.ipcc.ch/about/ (last visited July 17, 2023).
[36] IPCC, *Climate Change 2021*, *supra* note 10, at 425.
[37] Climate Action, *Causes and Effects of Climate Change*, https://www.un.org/en/climatechange/science/causes-effects-climate-change#:~:text=Fossil%20fuels%20%E2%80%93%20coal%2C%20oil%20and,of%20all%20carbon%20dioxide%20emissions (last visited July 17, 2023).
[38] 88 Fed. Reg. at 33259.
[39] *Id*. at 33260.
[40] EPA, *Sources of Greenhouse Gas Emissions* (Apr. 28, 2023), https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.
[41] EPA, Regulatory Impact Analysis, Docket ID No. EPA-HQ-OAR-2023-0072-0007, at 4-16, tbl.4-3 (2023) [hereinafter *RIA*].
[42] *See* Comment of NYU Inst. for Pol'y Integrity et al. on the Consideration of the Social Cost of Greenhouse Gases (Aug. 8, 2023, filed to this docket), at tbls.1 & 2 (showing monetized climate benefits for EPA's proposal as high as $212 billion when applying the latest available science and evidence on discounting and climate valuations).
[43] *RIA* at 4-46, tbl.4-12.

example, Commenters estimate that in 2030, CO_2 emissions reductions in a scenario representing the recommended improvements would yield benefits ranging between $3.0 to $29 billion (2022 dollars).[44] Additionally, the monetized benefits of the projected changes in SO_2 and NO_x in this case would range between $12 to $13.5 billion (2022 dollars) in 2030 alone.[45]

Table 1. Annual CO_2 Emissions Reductions for Preferred Policy Case (Compared to NRDC Reference)

	million short tons	million metric tonnes
2028	83	75
2029	83	75
2030	146	133
2031	146	133
2032	80	73
2033	80	73
2034	67	61
2035	67	61
2036	67	61
2037	364	330
2038	364	330
2039	210	190
2040	210	190
2041	210	190
2042	210	190

[44] These estimates of monetized benefits from CO_2 reductions were derived using the Interim Social Cost of Carbon values given in Table 4-1 of the RIA and the projected CO_2 emissions reductions of Commenters's scenario assuming recommended improvements to the proposed standards.

[45] Estimates of monetized benefits from SO_2 and NO_x reductions were derived using the total dollar value (mortality and morbidity) per ton of directly emitted $PM_{2.5}$ and $PM_{2.5}$ precursors reduced specifically for electricity generating units in 2030 taken from Tables 10 and 11 in EPA, *Technical Support Document: Estimating the Benefit per Ton of Reducing PM2.5 and Ozone Precursors from 21 Sectors* (April 21, 2023), https://www.epa.gov/system/files/documents/2021-10/source-apportionment-tsd-oct-2021_0.pdf.

Table 2. Benefits of Reduced CO_2 Emissions in Preferred Policy Case, 2028 to 2042 (millions of 2022$)

	SC-CO_2 Discount Rate and Statistic (millions of 2022$)			
Emissions Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2028	1,591	5,216	7,603	15,736
2029	1,680	5,304	7,691	16,001
2030	2,972	9,543	13,766	28,784
2031	3,129	9,699	14,079	29,410
2032	1,713	5,396	7,795	16,446
2033	1,799	5,482	7,880	16,789
2034	1,509	4,741	6,753	14,367
2035	1,580	4,813	6,824	14,583
2036	1,652	4,885	6,896	14,870
2037	8,959	26,876	38,171	82,185
2038	9,348	27,265	38,561	83,743
2039	5,383	15,926	22,655	48,899
2040	5,608	16,150	22,880	49,797
2041	5,832	16,375	23,104	50,694
2042	5,832	16,823	23,552	51,367

III. Legal Background

The core purpose of Section 111 of the Clean Air Act is to mitigate the harms to public health and welfare inflicted by emissions of air pollutants from categories of stationary sources—including new and existing sources—that contribute significantly to one or more air pollution problems.[46] Fossil-fuel-fired steam generating units, and, separately, combustion turbines (CTs), were listed as categories of significant contributors and regulated under Section 111(b)(1) in the 1970s.[47] EPA combined these sources in a single category in 2015,[48] finding then that their emissions of GHGs alone would render them significant contributors and warrant regulation of those emissions under Section 111.[49] Both the prior "endangerment finding" for GHGs and the GHG-specific "significant contribution finding" for fossil-fuel-fired EGUs have since been upheld by the U.S. Court of Appeals for the D.C. Circuit.[50]

Nearly fifteen years have elapsed since EPA found that GHGs endanger public health and welfare.[51] In that time, both the impacts of GHGs and the evidence of those impacts have come into an increasingly sharp focus, as documented elsewhere in these comments. Yet most power

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[46] *See* 42 U.S.C. § 7411(b)(1)(A).
[47] *See* 44 Fed. Reg. 33580 (June 11, 1979); 42 Fed. Reg. 53657 (Oct. 3, 1977); 36 Fed. Reg. 24875 (Dec. 23, 1971).
[48] *See* 80 Fed. Reg. 64510, 64531-32 (Oct. 23, 2015).
[49] *See id.* at 64530-31.
[50] *See Coal for Responsible Regulation v. EPA*, 684 F.2d 102, 117-23 (D.C. Cir. 2012); *Am. Lung Ass'n v. EPA*, 985 F.3d 914, 977 (D.C. Cir. 2021), *rev'd on other grounds sub nom. West Virginia v. EPA*, 142 S. Ct. 2587 (2022).
[51] 74 Fed. Reg. 66496 (Dec. 15, 2009).

plant emissions of carbon dioxide are still unregulated. The proposed standards are legally-required, long-overdue, and badly-needed.

As explained below, the Supreme Court in *West Virginia v. EPA* provided a clear pathway for EPA to regulate power plant CO_2 on the basis of emission control technologies and practices applied at the plant. Congress reinforced that pathway in the IRA by (1) providing unprecedented incentives to deploy emission reducing technology and (2) amending the Clean Air Act to direct EPA to reassess the baseline emissions trajectory and adopt carbon regulations using its Clean Air Act authority.[52] Building on the IRA baseline and accounting for the incentives it provides for the deployment of such technologies, the agency must take swift action to complete this rulemaking and establish standards that achieve the maximum feasible emission reductions from these sources.

A. EPA Has the Clear Authority and Obligation to Set Stringent Performance Standards and Emission Guidelines for Greenhouse Gas Emissions From Fossil Fuel-Fired EGUs

In *West Virginia v. EPA*,[53] the Supreme Court affirmed EPA's authority to set standards under Section 111 in their "traditional" form—standards that "caus[e] plants to operate more cleanly" and "ensur[e] the efficient pollution performance of each regulated source."[54] The decision also affirms that EPA has the primary regulatory role in Section 111(d):

> The Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. It does so by again determining, as when setting the new source rules, "the best system of emission reduction ... that has been adequately demonstrated for [existing covered] facilities.". … The States then submit plans containing the emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA.[55]

So while the Court disapproved the novel interpretation of "best system of emission reduction" adopted in the 2015 Clean Power Plan (CPP), the decision defines a clear pathway for EPA to set effective carbon pollution standards for power plants: define the BSER based on applying pollution control technology to EGUs and set limits based on the emission reductions it can achieve.

Congress reinforced this pathway in enacting the IRA[56] six weeks after the *West Virginia* decision. Designed in part to reflect the *West Virginia* outcome, the IRA provides large tax incentives and grants to deploy a wide range of carbon-reducing technologies, including at least two—CCS and hydrogen—that fit the "traditional" model described by the opinion. These

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[52] *See* David Doniger, West Virginia*, The Inflation Reduction Act, and the Future of Climate Policy*, 53 Env't L. Rep. 10553 (2023), https://www.eli.org/sites/default/files/files-pdf/Doniger%20Feature%20July%202023.pdf [Attachment 1].
[53] 142 S. Ct. 2587 (2022).
[54] *Id.* at 2599, 2611, 2612.
[55] *Id*. at 2601-02.
[56] Pub. L. No. 117-169, 136 Stat. 1818 (2022).

incentives will accelerate the improvement and deployment of these technologies and dramatically reduce the cost of applying them for power companies and their customers.

Further, Title VI of the IRA[57] amends the Clean Air Act itself to clearly state what case law has long held: that GHGs are air pollutants subject to EPA regulation, and that Congress has clearly directed EPA to regulate power plant carbon emissions using its existing Clean Air Act authority. First, it amends the Clean Air Act in six provisions pertaining to power plants, motor vehicles, and other sources, defining "greenhouse gases" as "the air pollutants carbon dioxide, hydrofluorocarbons, methane, nitrous oxide, perfluorocarbons, and sulfur hexafluoride."[58] These are the same substances covered by EPA's post-*Massachusetts* endangerment finding issued in 2009.[59] These amendments remove any room for doubt about whether GHGs are air pollutants subject to EPA regulation under the Clean Air Act. The central holding of *Massachusetts* is now contained in express statutory text.

Second, the IRA adds a new Section 135 to the Clean Air Act entitled "Low Emissions Electricity Program," which addresses "domestic electricity generation and use."[60] This provision reinforces EPA's existing authority to regulate CO_2 emissions from existing power plants under Section 111(d). Subsection (a) provides funding to EPA for, among other things, these purposes:

> (5) …to assess…the reductions in greenhouse gas emissions that result from changes in domestic electricity generation and use that are anticipated to occur on annual basis through fiscal year 2031; and
>
> (6) …to ensure that reductions in greenhouse gas emissions are achieved through the use of the existing authorities of this Act, incorporating the assessment under paragraph (5).[61]

The first clause directs EPA to update its assessment of the no-regulation baseline—the emission reductions expected to occur due to business-as-usual industry trends and the IRA's incentives, without further standards. The second clause directs EPA to set new standards under its existing authority. As noted above, *West Virginia* recognized EPA's "traditional" authority to limit power plant carbon pollution under Section 111.

The IRA's tax credits and grants, in addition to those in the IIJA,[62] affect both the baseline assessment and the reductions achievable with EPA standards. First, the incentives related to the

[57] IRA, Title VI, Subtitle A, 136 Stat. 2063-78.
[58] IRA § 60101 (adding Clean Air Act § 132(d)(4)); § 60102 (adding Clean Air Act § 133(d)(2)); § 60103 (adding Clean Air Act § 134(c)(2)); § 60107 (adding Clean Air Act § 135(c)); § 60113 (adding Clean Air Act § 136(i)); § 60114 (adding Clean Air Act § 137(c)(4)). The same definition is included in IRA §§ 60105, 60106, 60108, 60111, 60112, & 60116, which appropriate funds to EPA for monitoring, reporting, and reducing GHG emissions under provisions of the Clean Air Act and other laws.
[59] EPA, Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66496 (2009).
[60] IRA, § 60107 (adding Clean Air Act § 135).
[61] *Id.* § 135(a)(5) & (6).
[62] Pub. L. 117-58 (2021).

power sector—*e.g.*, for deploying renewable generation, energy storage, transmission grid upgrades, CCS technology, and energy efficiency in buildings, appliances, and industry—will drive power sector investments that will reduce high-emitting generation, thus substantially lowering the no-regulation emissions baseline, see *infra* at IV.B. Second, a number of these techniques fall squarely within the Supreme Court's description of EPA's "traditional" standard-setting process under Section 111 (*i.e.*, "set[ting] performance standards based on measures that would reduce pollution by causing plants to operate more cleanly"). CCS, for example, is a traditional post-combustion scrubber that directly reduces CO_2 emissions at coal- and gas-fired power plants. The IIJA provided billions of dollars in support for the additional demonstration and scale-up of carbon capture technologies and associated downstream infrastructure.[63] The IRA increases the tax credit for capturing CO_2 and storing it deep underground to $85 per ton of sequestered CO_2.

The IRA also creates a new tax credit for clean hydrogen production.[64] Using hydrogen as a power plant fuel is another potential carbon pollution control measure consistent with *West Virginia.* However, it is critical that effective rules ensure that hydrogen is in fact very low GHG, taking into account the emissions associated with how it is produced. Otherwise burning hydrogen in power plants could *increase* overall emissions. Even very low GHG hydrogen may not achieve as much reduction in emissions as CCS.[65] We address this issue further at Appendix B, Sec. VI.

Consistent with *West Virginia*, the proposed standards—and Commenters' recommended adjustments—are premised on applying adequately demonstrated, reasonable-cost technology to individual units within the source categories. Taking lead-time and costs into account, the proposed rules would adopt different emission rate limits and deadlines for various subcategories of coal- and gas-fired generating units considering, among other things, how long they will operate and how much they will be used. By reducing the cost of CCS for power companies and their customers, the IRA has strengthened the economic case for selecting that technology as the BSER.

The proposal standards (and our recommended changes) make no "transformative expansion in [EPA's] regulatory authority."[66] They are grounded in the 50-year-old Clean Air Act as it has been interpreted by the Court, and newly backed by the IRA's clear statement of congressional intent to create incentives for the relevant technologies and accompanying amendments to the Clean Air Act explicitly incorporating GHGs.

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[63] *Id*. This includes $3.47 billion for carbon capture demonstration and pilot projects; $2.1 billion in loans and grants for CO_2 transportation infrastructure, and $2.5 billion for the commercialization of CO_2 storage projects. *See* Carbon Capture Coalition, *Recently-enacted Infrastructure Investment and Jobs Act to Bolster Economywide Deployment of Carbon Management Technologies upon Full Implementation* (Jan 21, 2022), https://carboncapturecoalition.org/recently-enacted-infrastructure-investment-and-jobs-act-to-bolster-economywide-deployment-of-carbon-management-technologies-upon-full-implementation.

[64] *Id.* § 13204 (adding 26 U.S.C. § 45V).

[65] Rachel Fakhry, *Success of IRA Hydrogen Tax Credits Hinges on IRS and DOE* (Dec. 8, 2022), https://www.nrdc.org/bio/rachel-fakhry/success-ira-hydrogen-tax-credit-hinges-irs-and-doe.

[66] *West Virginia v. EPA*, 142 S. Ct. 2587, 2610 (2022).

Though the new standards will be based on the reductions achievable by applying technology to the sources, they are performance standards and will not require companies to use specific technology. Rather, companies will make their own choices whether to retrofit existing plants with the best system for the relevant subcategory or some other system, or to replace them, leveraging the IRA's incentives available for either course. To be sure, EPA must show that the emission rates and schedules it promulgates are achievable and cost-reasonable. That is a relatively ordinary showing governed by the deferential "arbitrary and capricious" standard of review.

Some may contend that these standards will lead to shifts in power generation from coal and gas to cleaner alternatives, and claim that that effect makes the rule the same as the one struck down in *West Virginia.* First, it must be emphasized that the vast majority of the expected changes in the make-up of the power sector are attributable to underlying industry trends and the IRA's incentives *before* the application of any new EPA standards. Second, *West Virginia* distinguished between deliberately *mandating* "generation-shifting" or market-share changes (which it held beyond EPA's power) and the exercise of EPA's traditional authority to set standards based on pollution control measures that improve a source's emissions performance. The Court noted the "obvious difference" between the CPP, which the Court found was expressly based on mandating such shifts, and traditional technology-based standards that produce such shifts "incidental[ly]," as a byproduct of the costs of applying pollution controls to individual plants' emissions.[67] The latter effect flows from nearly every Section 111 standard – indeed from nearly every kind of pollution control standard. Absent regulation, sources typically do not use demonstrated emission control technology because costs would increase. When a regulation sets emission limits that are based on such technology, some sources adopt that technology, and others choose to retire or limit operations for economic reasons.

In sum, acting well within the boundaries of *West Virginia* and the incentives and directives of the IRA, EPA has strong authority to set the proposed standards and guidelines for carbon pollution from power plants.

B. Determining the Degree of Emission Reduction that Reflects the Best System of Emission Reduction

The following subsections address the component findings EPA must make in determining the degree of emission reduction reflective of the BSER for each subcategory EPA has designated. In Section VI of these comments, Commenters focus on EPA's determinations that CCS, gas co-firing, and hydrogen co-firing are the BSER for specific subcategories of EGUs.

1. The Role of Subcategorization in Determining the BSER

Section 111 grants EPA the discretion to distinguish between classes, types, and sizes of sources when establishing emissions standards. EPA correctly interprets this provision to generally allow for subcategorization of sources on the basis of "characteristics that are relevant to the controls they can apply to reduce their emissions." We also agree that "subcategorization is appropriate for a set of sources that have qualities in common that are relevant for determining what controls

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[67] 142 S. Ct. at 2613, n.4.

are appropriate for those sources."[68] While the terms "type" and "class" grant EPA broad discretion in determining subcategories, a reasoned choice requires consideration of the real-world characteristics of the sources within a category, and how those characteristics influence appropriate pollution controls.

EPA has subcategorized sources based on input and output capacity, type of fuel input, type of process used, geographic location, and other characteristics in dozens of prior Section 111 rules.[69] EPA's proposed subcategories, as modified by Commenters recommendations described below, are analogous to those in prior rules, with differences that are appropriate for this industry and this pollutant.

2. "Adequately Demonstrated," "Available," "Achievable," and Similar Terms Convey Congress's Technology-Forcing Intent

Section 111 requires EPA to "identify the emission levels that are 'achievable' with 'adequately demonstrated technology.' After EPA makes this determination, it must exercise its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations."[70] Under this analysis, "the amount of air pollution [is] a relevant factor to be weighed when determining the optimal standard."[71] The system chosen must reduce emissions the best considering the relevant factors.

Section 111, like many other Clean Air Act provisions, is a technology-forcing.[72] Congress expected standards of performance under Section 111 to "press for the development and application of improved technology,"[73] and the statute "looks toward what may fairly be projected for the regulatory future, rather than the state of the art at the present."[74] Following this approach, for the purposes of Section 111,

> An adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way. An achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level

[68] 88 Fed. Reg. at 33270.
[69] *Id.* at 33271.
[70] *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981).
[71] *Id.* at 326.
[72] *See Union Electric Co. v. EPA*, 427 U.S. 246, 256-57 (1976) (describing Clean Air Act requirements as having a "'technology-forcing character,' and are expressly designed to force regulated sources to develop pollution control devices that might at the time appear to be economically or technologically infeasible" (citation omitted) (quoting *Train v. NRDC*, 421 U.S. 60, 91 (1975)); *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 592 (2001) (Breyer, J., concurring) ("Subsequent legislative history confirms that the technology-forcing goals of the 1970 amendments are still paramount to today's Act.").
[73] *NRDC v. EPA*, 655 F.2d 318, 331 (D.C. Cir. 1981) (citing S.Rep. No. 1196, 91st Cong., 2nd Sess. 24 (1970)); *see also Int'l Harvester Co. v. Ruckelshaus*, 478 F.2d 615, 622-23 (D.C. Cir. 1973) ("The state of the art has tended to meander along until some sort of regulation took it by the hand and gave it a good pull.").
[74] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).

that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.[75]

Considering this technology-forcing aspect of the Clean Air Act, reviewing courts have upheld EPA standards on the basis of (1) "literature review and operation of one plant in the U.S,"[76] (2) "various test programs,"[77] (3) "pilot plant technology,"[78] and (4) "testimony from experts and vendors."[79] EPA may also base standards upon "the reasonable extrapolation of a technology's performance in other industries"[80] and project "technological improvements" based on "known elements" of existing pollution control systems, including where EPA has concluded "manufacturers could 'improve, test, and apply' technology during the lead time period" for compliance.[81] A standard of performance is "achievable" if it is "within the realm of the adequately demonstrated system's efficiency," although it "need not necessarily be routinely achieved within the industry prior to its adoption."[82]

The fact that EPA must review and, if appropriate, revise Section 111 standards at least every eight years does not limit the time horizon for EPA's assessment of appropriate lead time and compliance deadlines. To be sure, as part of each such review, EPA needs to consider whether current information shows past projections were either too aggressive or too conservative. If appropriate, a subsequent review can result in accelerating or slowing down the timeline for new sources, as applicable. EPA's long-held position is that "if a technology is 'adequately demonstrated' for use at a date in the future, EPA could establish a future-year standard based on that technology. This allows EPA to develop two- or multi-phased standards with more stringent limits in future years that take into account and promote the development of technology."[83]

A prominent case study of this statutory mandate in action is provided by flue gas desulfurization (FGD) post-combustion sulfur scrubbers that EPA has based SO_2 emission standards on since the 1970s.[84] Even though there were only three in operation at the time EPA proposed the rule, the D.C. Circuit upheld EPA's SO_2 standards as adequately demonstrated, achievable, and "the result of reasoned decision-making."[85] The court held EPA was justified in concluding that the systems were adequately demonstrated based on "tests of prototype and full-scale control systems, considerations of available fuel supplies, literature sources, and documentation of

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[75] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433–34 (D.C. Cir. 1973).
[76] *Id.* at 434.
[77] *Nat'l Petrochemical & Refiners Ass'n v. EPA*, 287 F.3d 1130, 1137 (D.C. Cir. 2002) (upholding Clean Air Act Section 202(a)(3) standards for new motor vehicles, which have a similar basis as Section 111 standards).
[78] *Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1061 (3rd Cir. 1975) (upholding Clean Water Act standards and guidelines, which are based on the best practicable technology currently available); *cf. FMC Corp. v. Train*, 539 F.2d 973, 983–84 (4th Cir. 1976) (upholding EPA's decision to set Clean Water Act guidelines based on data from a single pilot plant).
[79] *Portland Cement Ass'n,* 486 F.2d at 402.
[80] *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1978).
[81] *Int'l Harvester Co.*, 478 F.2d at 629 (quoting EPA decision on technology availability for congressionally-set 90 percent emission reduction standard).
[82] *Essex Chem. Corp.*, 486 F.2d at 433-34.
[83] 73 Fed. Reg. 44354, 44487 (July 30, 2008).
[84] *See infra* Section VII.C. for further discussion of the regulatory drivers of the development and adoption of SO_2 and NO_x controls.
[85] *Essex Chem. Corp.*, 486 F.2d at 440.

manufacturer guarantees and expectations."[86] Due to that standard and subsequent EPA regulations, today 93 percent of the SO_2 produced by combustion of fuels in power plants never reaches the atmosphere.[87] In *West Virginia v. EPA*, the Supreme Court described "add-on controls" and "fuel-switching" as "more traditional air pollution control measures."[88] The Court cited a 2005 standard based on the installation and operation of "wet scrubbers"—the very technology ruled adequately demonstrated back in the 1970s—as one "entry in an unbroken list of prior Section 111 rules that devised the enforceable emissions limit by determining the best control mechanisms available for the source."[89]

To sum up the sulfur scrubber story, EPA first set standards in 1971 based on a technology that was not yet in widespread use. EPA reinforced the scrubber-based standard in 1979. Industry then applied the technology widely. Decades later the Supreme Court cited this experience as a marquee example of a "traditional air pollution control measure"[90] within EPA's authority. The Clean Air Act, and Section 111, still retain that technology-forcing approach.

3. Consideration of Costs

Section 111(a)(1) states that EPA must "tak[e] into account cost" when determining the BSER and the emission limitation it can achieve. Consistent with case law and EPA's long-standing practice, in this proposal EPA approaches the cost component of its "best system" analysis in terms of reasonableness: the best system has costs that are reasonable.[91] We support the various cost metrics that EPA has considered to establish the reasonableness of the proposed standards: The costs are in the range the industry can absorb; the incremental cost of generation (in $/megawatt-hour (MWh)) is comparable to or less than similar values in other power-sector regulations; cost-effectiveness (in $/ton of CO_2 abated) is comparable to or less than similar values in other GHG regulations; and benefits greatly outweigh costs.

a. Total Cost

The D.C. Circuit has upheld standards whose costs were not "exorbitantly costly in an economic . . . way[,]"[92] and were of a magnitude the industry could successfully absorb.[93] Similarly, the D.C. Circuit upheld another standard where petitioners had not shown that "the costs of meeting standards would be greater than the industry could bear and survive," or that the industry could not "adjust itself in a healthy economic fashion" to comply while continuing to meet demand for its products.[94]

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[86] *Id.*
[87] *See* EPA, *Acid Rain Program Results*, https://www.epa.gov/acidrain/acid-rain-program-results (last accessed Aug. 5, 2023). Congress in 1990 responded to the need for additional pollution reductions, and to the state of technology then in place enacting Title IV of the Act. With IRA, Congress also has recognized both the need for and promise of carbon-reducing demonstrated technologies.
[88] *See* 142 S. Ct. at 2611 (quoting 80 Fed. Reg. at 64784).
[89] *Id.* at 2610-11. The 2005 rule was vacated without a court ruling on its legality under Section 111, and the Court used the wet scrubbers as an example only after assuming the rule was valid. *See id.*
[90] *West Virgini*a, 142 S. Ct. at 2611.
[91] 88 Fed. Reg. at 33273.
[92] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973).
[93] *See id.*
[94] *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975).

Comparison of this rule with prior rules shows that the total costs of this rule fall within the range of prior standards that the courts have upheld. For example, the projected annual compliance cost of $4.6 billion (2019$) in 2030[95] amounts to just 1.9 percent of total power sector expenditures in 2019[96] and 1.1 percent of total power sector revenues in 2019.[97]

The IRA tax credits sharply reduce the cost of applying CCS to coal and gas power plants, and the cost of deploying cleaner generation resources to replace dirtier sources. The latter incentives remain in place until power-sector CO_2 emissions reach 75 percent below 2022 levels post-2032.[98] Here, the "basic and consequential tradeoffs" are ones that Congress made itself.[99] Through the IRA, Congress has clearly decided to incentivize these technologies and has clearly told EPA to set new standards taking those incentives into account. Thus, when EPA considers cost in its new standards, only the portion of the costs that will be borne by power plant operators and their customers is the proper basis for determining the costs of the proposed rule.

b. Cost per Megawatt-hour

EPA further indicates that within-industry comparison of impacts on the cost of generation (in $/MWh) across power-sector regulations may be relevant to its "best system" analysis.[100] While such comparisons may not be appropriate in every case, given different statutory requirements, here they plainly illustrate that the costs of control are reasonable. For example, the $/MWh value for deploying CCS within the long-term subcategory for coal units is negative (given 45Q tax credits),[101] while the incremental $12/MWh for the typical medium-term coal unit from co-firing natural gas is less than corresponding values in past power sector regulations.[102] The $8.6/MWh for a typical existing gas unit installing and operating CCS (again assuming 45Q credits) is even lower.[103]

c. Cost per ton

Similarly, cost-effectiveness may also indicate cost-reasonableness, to the extent that past rules accepting higher $/ton values entailed reasonable costs. Under EPA's proposal, the gain of

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[95] *RIA* at 3-17, tbl. 3-7. These compliance costs do not include costs associated with the proposed emission guidelines for existing gas-fired EGUs, which were not modeled.
[96] *See* EPA, Supplemental Data and Analysis for the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units – Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding; Notice of Proposed Rulemaking (Docket ID: EPA-HQ-OAR-2018-0794-4586) at 20, tbl. A-6 (Sept. 2021) (showing total expenditures of 200.7 billion dollars (2007$) in 2019), https://www.regulations.gov/document/EPA-HQ-OAR-2018-0794-4586. Total expenditures were converted to $242.9 billion ($2019) using the Gross Domestic Product: Implicit Price Deflator. *See* Fed. Reserve Bank of St. Louis, FRED, *Gross Domestic Product: Implicit Price Deflator*, https://fred.stlouisfed.org/series/GDPDEF# (last visited Aug. 7, 2023).
[97] *See* EIA, *Electric Power Annual 2021*, tbl. 2.3 (Nov. 7, 2022), https://www.eia.gov/electricity/annual/ (showing total revenue from sales of electricity to ultimate customers of $401.738 billion in 2019).
[98] IRA § 13701(a).
[99] *Biden v. Nebraska*, 133 S. Ct. 2355 (2023) (quoting *West Virginia*, 142 S. Ct. at 2613).
[100] 88 Fed. Reg. at 33273.
[101] *Id.* at 33348.
[102] *Id.* at 33353.
[103] *See* EPA, *Technical Support Document: GHG Mitigation Measures for Combustion Turbines* (2023), Docket ID No. EPA-HQ-OAR-2023-0072-0057, at 12 [hereinafter *GHG Mitigation Measures for Combustion Turbines TSD*], https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0057.

$8/ton for long-term coal units deploying CCS,[104] and the costs of $66/ton for medium-term coal units deploying gas co-firing,[105] and $26/ton for an existing gas unit deploying CCS[106] are all well below the $98/ton of CO_2e reduced in EPA's 2016 New Source Performance Standards (NSPS) for oil and gas sources.[107] They are also all well below any appropriate evaluation of the social cost of carbon, such as the $140 to $380 per ton of CO_2 emitted in 2030 (depending on discount rate) that the agency determined in its analysis for the supplemental proposal of NSPS and EGs for oil and gas methane sources last fall.[108]

d. Cost and benefit

EPA also should weigh the rule's projected compliance costs together with its benefits to confirm its cost reasonableness. The Supreme Court has previously suggested, in different statutory contexts, that consideration of a rule's benefits is relevant to a determination of cost reasonableness.[109] Comparing total climate benefits based on the tons of CO_2 emissions reduced and the total benefits of other air pollution reductions to costs, EPA projects net benefits upwards of $16 billion (2019 $) in 2030[110] and cumulative net benefits with a present value of $85 billion (2019 $).[111] These assessments confirm the proposed rules' reasonable cost.[112]

One final note on accounting for cost. Under Section 111, EPA's assessment of reasonable costs must be made with respect to the typical sources in a category or subcategory, not with respect to the most economically marginal sources within the grouping. The statute specifically provides a mechanism for considering variances based on remaining useful life or other factors (RULOF) for individual sources within a subcategory that exhibit fundamentally different cost characteristics. This underscores that such a source's economic position is not relevant when EPA determines the cost-reasonableness of the emission reduction that reflects the "best system" for a category or subcategory.

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[104] 88 Fed. Reg. at 33348.
[105] *Id*. at 33353.
[106] *See* EPA, *GHG Mitigation Measures for Combustion Turbines TSD*, *supra* note 103, at 12.
[107] *See* 88 Fed. Reg. at 33353.
[108] *See* EPA, External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances (Docket ID: EPA-HQ-OAR-2021-0317) at 3, tbl. ES.1 (Sept. 2022), https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf; *see also* Comments of Institute for Policy Integrity at NYU Law School submitted to this docket (applying the updated social cost of carbon, as well as a lower discount rate, to projected emission reductions from EPA's proposed rule). These estimates of the social cost of CO_2 are dramatically understated because of missing categories of damages, such as harms from intensified precipitation. See, e.g., Cropper et al., External Letter Peer Review of Technical Support Document: Social Cost of Greenhouse Gas, at 30-31 (May 4, 2023), https://www.epa.gov/system/files/documents/2023-05/Final%20SCGHG%20Comments%20Summary%20Report%205.4.23_0.pdf.
[109] *See Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 225-26 (2009). *See also Michigan v. EPA,* 576 U.S. 743, 753 (2015) ("reasonable regulation ordinarily requires paying attention to the advantages *and* the disadvantages of agency decisions").
[110] *RIA* at 7-4, tbl. 7-2. As noted, compliance costs and benefits do not include impacts associated with the proposed emission guidelines for existing gas-fired EGUs, which were not modeled.
[111] *Id.* at 7-6, tbl. 7-5.
[112] In its net benefits analysis, EPA properly includes the costs to the power sector and its customers, which excludes the IRA tax credits. The tax credits are transfers under Circular A-4 but are not properly considered direct costs of the rule. *See* Comments of Institute for Policy Integrity at NYU Law School submitted to this docket.

4. Energy considerations

EPA correctly observes that "[e]nergy requirements may include the impact, if any, of the air pollution controls on the source's own energy needs," as well as the impact of potential pollution controls on "the energy system, on a sector-wide, regional, or national basis, as appropriate."[113] Among other things, the requirement to consider energy requirements may include consideration "whether controls [EPA] is considering would create risks to the reliability of the electricity system in a particular area or nationwide and, if they would, to reject those controls as the BSER."[114] Section 111 "*requires* EPA to take into account … energy considerations."[115] Thus, EPA has an obligation to consider the effects of its rules on "energy requirements" at a national level—in other words, "our Nation's energy needs"[116]—not just at the level of the individual source. This spring, EPA and the U.S. Department of Energy (DOE) entered into a memorandum of understanding to create a framework on electric sector resource adequacy and operational reliability,[117] which the North American Electric Reliability Corporation (NERC) commended.[118] EPA also evaluates resource adequacy through the power sector modeling that it conducts, which demonstrates how compliance can be achieved while also meeting all electricity demand and reserve margins.

5. Other Environmental Impacts

EPA correctly considers environmental effects beyond emissions levels in determining BSER, including emissions associated with fuel production. Prior to the 1977 Clean Air Act amendments, the D.C. Circuit held Section 111's "standard of the 'best system' is comprehensive, and we cannot imagine that Congress intended that 'best' could apply to a system which did more damage to water than it prevented to air."[119] That court also held that the Administrator must consider "counter-productive environmental effects" when determining BSER.[120] This included considering the effects of wastes or by-products associated with technology used to achieve the BSER.[121] Confirming this ruling, Congress's 1977 amendments added the phrase "any nonair quality health and environmental impact" to the list of factors in Section 111.[122]

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[113] 88 Fed. Reg. at 33274.
[114] *Id.*
[115] *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 183 (D.C. Cir. 2011) (emphasis in original) (quoting 42 U.S.C. § 7411(a)(1)).
[116] *Am. Elec. Power Co. v. EPA*, 564 U.S. 410, 427 (2011).
[117] *See* EPA & DOE, Joint Memorandum on Interagency Communication and Consultation on Electric Reliability (Mar. 9, 2023), https://www.epa.gov/system/files/documents/2023-03/DOE-EPA%20Electric%20Reliability%20MOU.pdf.
[118] *See* NERC, Press Release, Statement on EPA, DOE Agreement Supporting Electric Reliability (Mar. 10, 2023), https://www.nerc.com/news/Pages/Statement-on-EPA,-DOE-Agreement-Supporting-Electric-Reliability.aspx.
[119] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 385 n.42 (D.C. Cir. 1973), *cert. denied,* 417 U.S. 921 (1974).
[120] *Id.* at 385; *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 438-39 (D.C. Cir. 1973).
[121] *See Essex Chem. Corp.*, 486 F.2d at 441 (remanding to EPA to "for further consideration and explanation by the Administrator of the adverse environmental effects").
[122] *See Nat'l Lime Ass'n v. EPA*, 627 F.3d 416, 428 n.43 (D.C. Cir. 1980) ("The last new requirement, that the Administrator take into account the nonair quality health and environmental impact and energy requirements, was already a part of the case law developed under section 111.").

EPA is therefore well within its authority to consider the other environmental impacts of a system of emissions reduction, including proper disposal of carbon dioxide captured by CCS and the emissions associated with hydrogen fuel production.

C. Authority to Consider Permitting, Infrastructure, and Other Logistics in Determining Appropriate Lead Time

EPA recognizes that "lead time" for compliance is a relevant factor in determining how much improvement standards may require, and that it has authority under Section 111 to promulgate standards of performance and emission guidelines that provide "lead time" for compliance.[123] In enacting the Clean Air Act, Congress contemplated that the agency would not require immediate conformity to standards but instead match compliance deadlines to the pace at which widespread accessibility of the best system can reasonably be implemented.[124] In this vein, the D.C. Circuit has observed that "the question of availability [of pollution control technology] is partially dependent on 'lead time,' the time in which the technology will have to be available."[125] Accordingly, EPA has issued several rules under Section 111 in which it has set future compliance deadlines to allow time for the "best system" to be deployed across an industry.[126] Like its determinations of appropriate categories, EPA's determination of appropriate compliance deadlines is a highly technical factual inquiry on which the agency deserves substantial deference under the arbitrary and capricious test.[127]

EPA's authority to establish standards that reflect technology that, while adequately demonstrated when EPA issues the rule, will need time to become available to regulated sources is subject to a rule of reason.[128] Additional time for the controls to become available generally supports a greater degree of required technological development.[129] Further, although EPA's projection cannot reflect a "'crystal ball' inquiry," the agency's projection may prove more reliable when it is based on "known elements" of existing technologies.[130]

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[123] 88 Fed. Reg. at 33289.

[124] *See* S. Rep. No. 91-1196, at 16 (1970) ("[T]he technology must be available at a cost and at a time which [EPA] determines to be reasonable.").

[125] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d at 391-92.

[126] *See, e.g.*, 77 Fed. Reg. 56422, 56450 (Sept. 12, 2012) (deferring standards for modifications to certain refinery equipment by three years both to allow controls and monitors to be installed and to prevent excess emissions from unplanned startups and shutdowns); 77 Fed. Reg. 49490, 49525-26 (Aug. 16, 2012) (concluding that there was "no BSER" for storage vessels in the oil and gas subcategory during a one-year "adjustment period" "for manufacturers to be ready to supply the operators with the correct equipment they need"); 70 Fed. Reg. 39870, 39887 (July 11, 2005) (proposed rule; finalized at 71 Fed. Reg. 39154, 39158 (July 11, 2006)) (allowing three years to manufacture and certify fire pump engines); 56 Fed. Reg. 24468 (May 30, 1990) (proposed rule; finalized at 61 Fed. Reg. 9905, 9919 (Mar. 12, 1996)) (allowing three years for testing, control system design, and installation at new and existing landfills); 44 Fed. Reg. 29828, 29829 (May 22, 1979) (emission guidelines contemplating up to six years for retrofits of equipment at kraft pulp mills); 60 Fed. Reg. 10654, 10689 (Feb. 27, 1995) (proposed rule; finalized at 62 Fed. Reg. 48348, 48381 (Sept. 15, 1997)) (standard under Sections 111 and 129 providing up to five-and-a-half years for commercial waste disposal to scale up to receive wastes diverted from the regulated medical waste generators).

[127] *See, e.g.*, *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 292 (2016).

[128] *Portland Cement Ass'n*, 486 F.2d at 391 (citing *Int'l Harvester Co. v. Ruckelshaus*, 478 F.2d 615, 629 (D.C. Cir. 1973)).

[129] *See Int'l Harvester Co.*, 478 F.2d at 629.

[130] *See id.*

EPA is obliged to review and if appropriate revise Section 111 standards at least every 8 years. As discussed above, that review provision does not limit EPA's authority to project the pace at which technology can be applied and to set emission limits that take effect over longer timeframes. Rather, it suggests that EPA should review such projections at least every eight years and propose revisions as appropriate.

D. The Energy Policy Act of 2005

EPA is proposing not to re-open its prior interpretation that provisions of the Energy Policy Act of 2005 (EPAct05) "preclude the EPA from relying solely on the experience of facilities that received EPAct05 assistance, but do not preclude the EPA from relying on the experience of such facilities in conjunction with other information."[131] Even though the issue has not been reopened, we explain here why that interpretation is correct.

EPAct05 includes government-industry partnership programs and tax incentives intended to increase investment in coal-based power generation technologies that achieve significant improvements in efficiency and environmental performance.[132] This provision states:

> No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be [] adequately demonstrated for purposes of section 111 of the Clean Air Act.[133]

EPAct05 added similar language to the Internal Revenue Code for facilities receiving a tax credit for a qualifying project, providing that no use of a technology or achievement of an emission limit at a qualifying project "shall be considered to indicate that the technology or performance level is adequately demonstrated for the purpose of section 111 of the Clean Air Act."[134]

In 2015, EPA reasonably concluded, based on the plain language and congressional intent, that "these provisions … preclude the EPA from relying solely on the experience of facilities that received DOE assistance, but not to preclude the EPA from relying on the experience of such facilities in conjunction with other information."[135] Commenters agree that these provisions do not preclude EPA from considering evidence from such the facilities in conjunction with other demonstrations of the technology for the purposes of a Section 111 rulemaking. In fact, "[t]he corroborative information from EPAct05 facilities, though supportive, [are] not necessary to EPA's findings."[136]

The only court to consider the issue thus far agreed with this interpretation:

> The Court notes that § 402(i) only forbids the EPA from considering a given technology or level of emission reduction to be adequately demonstrated solely on

[131] 88 Fed. Reg. at 33291 (internal quotation marks and emendations omitted).
[132] 42 U.S.C. §§ 15961 *et seq*.
[133] 42 U.S.C. § 15962(i)(1).
[134] 26 U.S.C. § 48A(g)(1).
[135] 80 Fed. Reg. at 64541.
[136] 80 Fed. Reg. at 64542.

the basis of federally-funded facilities. 42 U.S.C. § 15962(i). In other words, such technology might be adequately demonstrated if that determination is based at least in part on non-federally funded facilities.[137]

E. Standards for Existing Coal Plants Set in 2024 for Compliance After 2030 Are Not Limited by the 2015 Standard for New Coal Plants

In 2015, EPA found partial CCS cost reasonable for new coal plants built after 2015. At that time, the 45Q tax credit was just $20/ton; now it has been increased to as much as $85/ton. And since then, more data have accumulated to show that CCS is feasible to apply at coal and gas plants, *see infra* at Sec. V.A. and Appendix A Sec. I. In this rulemaking, eight years later, EPA must make current, fresh determinations as to the BSER and appropriate compliance timeframes for various subcategories. The 2015 new source rule does not establish a "ceiling" for EPA's current determinations as to which plants CCS is adequately demonstrated at reasonable cost, and on what timetable. With additional carbon capture deployment, and greater incentives, the technology is primed to be the basis of more-stringent standards for the remainder of the fleet that would be applicable in 2030 and later. As EPA has observed, "[n]o provision in section 111, nor any statement in its legislative history, nor any of its case law, indicates that the standards for new sources must be more stringent than the standards for existing sources."[138]

F. A Requirement to Transfer Captured Carbon to a Facility Reporting under the GHGRP Does Not Render the System "Outside the Fence"

The fact that CCS may often involve transport and storage of CO_2 offsite does not render this system of emission reduction "beyond-the-source."[139] Many pollution control technologies that cause a source to operate more cleanly produce waste that must be handled and permanently disposed of, most often off-site. EPA is required to consider the "nonair quality . . . environmental" impacts of deploying the BSER as part of the BSER analysis under Section 111(a)(1).[140] This requirement reflects the fact that waste byproducts of air pollution control must be handled correctly, whether disposed of onsite or elsewhere.

Congress added the "nonair" statutory factor in 1977 confirming the D.C. Circuit's holding that EPA needed to consider the pollution potential of scrubber wastes in determining whether SO_2 scrubbers should be the basis of standards for sulfuric acid plants and coal-fired steam generators.[141] There, the court opined that EPA should have considered the effects of its rule on "the environment as a whole," suggesting the need for proper handling and disposal of wastes.[142] In turn, the House committee noted that the court held that EPA should have considered "land impacts"; the 1977 amendments generalized to the current phrasing of "nonair quality …

[137] *Nebraska v. EPA*, 2014 U.S. Dist. LEXIS 141898, at *9 n.1 (D. Neb. 2014).
[138] 80 Fed. Reg. at 64787.
[139] The Supreme Court in *West Virginia* did not rule on the question whether the "best system" must apply exclusively "to or at" the source, a contention that the D.C. Circuit roundly rejected. *See* 142 S. Ct. 257; *Am. Lung Ass'n*, 985 F.3d at 950-51.
[140] 42 U.S.C. § 7411(a)(1).
[141] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 439.
[142] *Id.*

environmental impacts."[143] Two years later, in the NSPS for SO_2, PM, and NO_x from new and reconstructed electric utility steam generating units, EPA made it clear that its BSER analysis involved "also evaluat[ing] the waste products that would be generated under alternative methods,"[144] and EPA's examination of waste disposal differences in control methods were noted and not disturbed by the D.C. Circuit in review of that rule.[145] In none of these cases did handling or disposal of wastes offsite render the best system beyond-the-source. This proposed rule imposes no duties on entities other than the regulated generating units. The obligation is only that regulated generators that capture CO_2 must comply with pre-existing EPA GHG reporting requirements or ship the captured CO_2 only to those other entities that comply with pre-existing GHG reporting requirements.

Notably, CCS differs from some other pollution controls insofar as its waste product is the regulated air pollutant itself. To ensure that sources deploying this control technique achieve the emission limitation reflecting CCS, EPA must require proper disposition of the captured CO_2 in its Section 111 rule. EPA's proposed requirement here—that captured CO_2 be managed at an entity subject to the GHGRP subparts designed for long-term containment, or otherwise be stored as effectively as geologic sequestration[146]—helps ensure that CO_2 waste will not reenter the atmosphere and thereby render EPA's emission limitation ineffective in actually reducing emissions to the air. Other state and federal authorities properly regulate the management of the CO_2 downstream.[147]

G. Regulated EGUs can comply with performance standards in any way they choose including through actions to reduce operations of affected units.

While the proposed standards are based on the reductions achievable by applying technology to individual units, as noted earlier they will not require companies to use that technology. That some operators may choose to comply with EGU-specific limits on CO_2 emissions by relying on some other lower-emitting generation resources does not call into question EPA's "best system" analysis or the resulting emission limitations. Section 111 provides for performance standards and (except under the limited conditions described in Section 111(h)) sources are free to choose any method of meeting the emissions performance required by the standard. Accordingly, the Supreme Court in *West Virginia v. EPA* recognized that "a source may achieve [an emission limitation under section 111] in any way it chooses; the key is that its pollution be no more than the amount achievable through the application of the best system of emission reduction adequately demonstrated."[148] In many instances, the power sector trends that have been ongoing and are predicted to accelerate will continue and fossil generation will continue to retire and run less. As noted earlier, pollution control rules almost always add some costs and this often causes operators to reduce reliance on the regulated unit as a business choice. However, Section 111 demands that EPA set standards for those EGUs that continue to operate based on the BSER.

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[143] H.R. Rep. No. 95-294, at 190 (1977) (citing *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 439 (D.C. Cir. 1973)).
[144] 44 Fed. Reg. 33580, 33603.
[145] *Sierra Club v. Costle*, 657 F.2d 298, 336 (discussing EPA's analysis of the amount of waste sludge produced by various control methods).
[146] 88 Fed. Reg. at 33328; proposed 40 C.F.R. §§ 60.5860b(f), 60.5555(f), 60.5555a(f).
[147] *See, e.g.*, *Hazardous waste management system: Conditional Exclusion for Carbon Dioxide (CO_2) Streams in Geologic Sequestration Activities*, 79 Fed. Reg. 350 (2014).
[148] 142 S. Ct. at 2601.

IV. EPA's Model of the Business-As-Usual Trajectory of the Power Sector Is Conservative and Well-Supported

EPA is proposing this critical set of standards and guidelines at a dynamic time for the source category. By understanding the trends and trajectory of the source category, EPA can harmonize the rules' emission limits with the shifting role of fossil-fueled generators while also providing the long timelines, subcategories, and flexibilities to enable the source category to provide clean, affordable and reliable electricity. EPA's approach to modeling the business-as-usual baseline is reasonable and thoroughly supported by its record.[149] In this section, Commenters describe the recent trends in the regulated industry's role within the power sector, the anticipated changes in the future, and EPA's approach to modeling the impact of the shifting role of the source category as shaped by the incentives recently passed by Congress.

A. Recent Power Sector Trends

The United States power sector has undergone significant transition over time, driven by technological advancement, economic considerations, environmental concerns, and policy changes. Through the mid-19th century, centralized power generation was primarily from coal power plants. Between 1960 and 1980, a significant number of nuclear power plants were constructed to supplement coal generation. Beginning in the 1970s, the power sector experienced diversification as environmental concerns over fossil fuels grew, prompting research into renewables such as solar and wind. The next significant structural shift in generation capacity mix began in 2008 when hydraulic fracturing combined with horizontal drilling technology enabled economic extraction of unconventional natural gas. In the 2010s, the cost of solar and wind technologies fell dramatically, making them increasingly competitive with natural gas, for adding new capacity and replacing the aging generation assets, most of them coal-fired generating units.

The impact of these trends on the coal-fired generation fleet has been significant. In 2005, the operating capacity of coal-fired units was 321 gigawatts (GW), with an annual total generation of 1,950 gigawatt-hours (GWh). Since 2012, approximately 10 GW of coal capacity has retired each year. During 2022, U.S. coal retirements totaled almost 12 GW, decreasing total coal-fired capacity to 219 GW. Over this period, coal-fired electricity generation declined even more rapidly than the reduction in coal capacity, plummeting by 65 percent to an annual total of 665 GWh in 2022.[150]

As of the end of 2022, an additional 68 GW of coal-fired capacity were already scheduled to retire by the end of 2030–a likely underestimation of retirement given past trends. This is due to the fact that not all retirements are announced well in advance. Thus, while announced

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[149] *See, e.g.*, *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 43 (1983) ("[A]gency must examine the relevant data and articulate a satisfactory explanation for its action…"); *Bluewater Network v. EPA*, 370 F.3d 1, 22 (D.C. Cir. 2004) (Agency must "provide a reasoned explanation of its basis for believing that its projection is reliable. This includes a defense of its methodology for arriving at numerical estimates[.]").

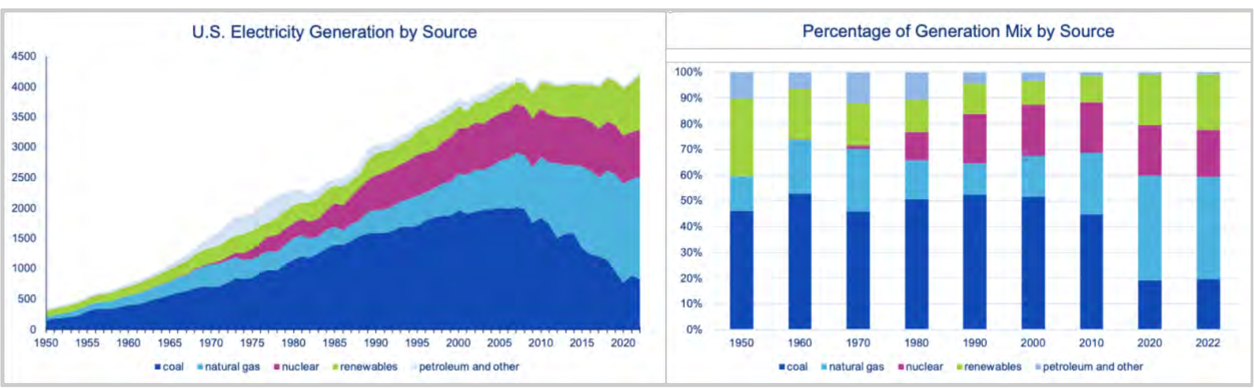
[150] Metin Celebi et al., *A Review of Coal-Fired Electricity Generation in the U.S.* 3 (2023), https://www.brattle.com/wp-content/uploads/2023/04/A-Review-of-Coal-Fired-Electricity-Generation-in-the-U.S..pdf.

retirements are an effective indicator of near-future actions, their predictive accuracy decreases for long-term projections. Additionally, operators may have made retirement decisions without immediately announcing them, and unforeseen changes in market or regulatory factors may advance or slow the retirement schedule unexpectedly.[151]

The average capacity factors of coal-fired generators have declined over time as their units have shifted from providing baseload power to more intermediate load operation. In 2008 the average capacity factor of coal-fired EGUs was 73.4 percent, and had fallen to 47.8 percent by the end of 2002.[152]

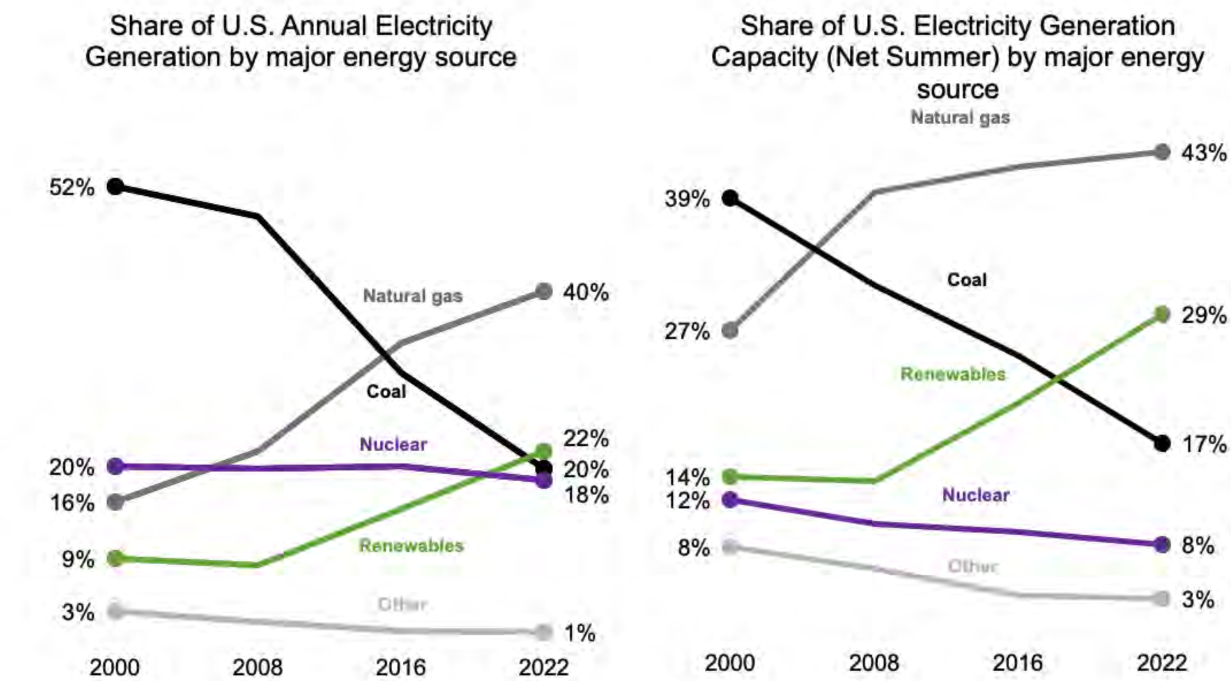
The average age of coal-fired generators has increased from 28 years in 2000 to 47.2 years by the end 2022, and this trend is expected to continue due to the lack of new coal-fired generators coming online.[153]As coal-fired generators age, they tend to operate less frequently and less efficiently, resulting in lower capacity factors and higher heat rates (amounts of fuel burned per unit of power produced). Cycling coal-fired generators, which occurs when they operate less often, can lead to higher heat rates and increased emission rates. Investment in coal-fired generators declines as they age, with annual non-fuel operation and maintenance expenditures decreasing over time. The decline in capacity factors and efficiency of coal-fired generators is also influenced by market conditions, such as increased competition from natural gas and renewable technologies.[154]

Figure 1a. U.S. Electricity Generation by Source, 1950–2022



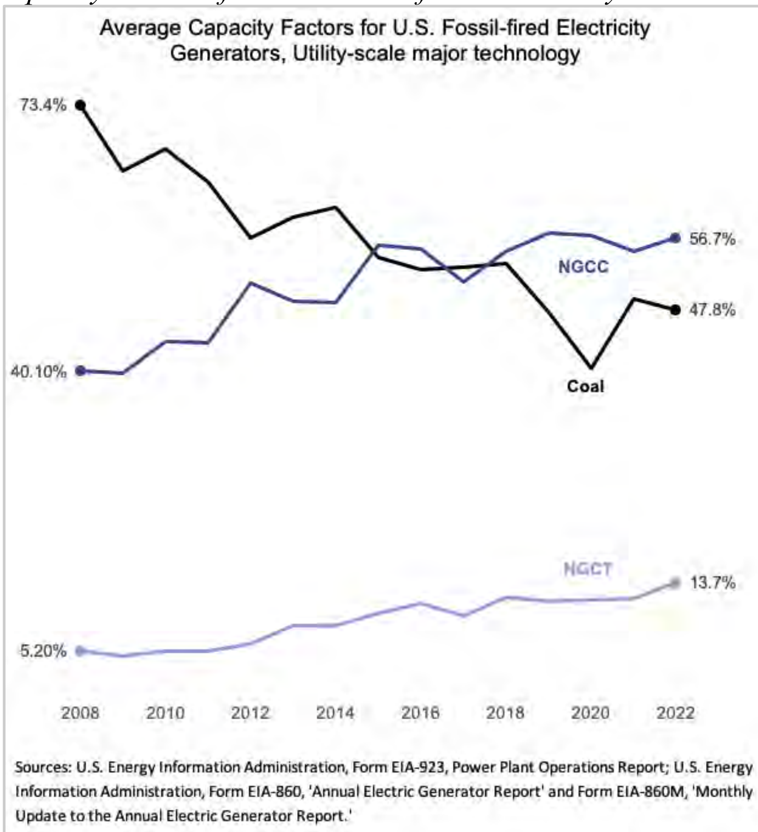
[151] *Id.* at 6.
[152] EIA, *Electric Power Monthly: Table 6.07.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels*, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_07_a (last visited July 28, 2023) [hereinafter EIA, *Table 6.07.A.*].
[153] Celebi et al., *supra* note 150, at 18.
[154] EPA, *Technical Support Document: Power Sector Trends*, Docket ID No. EPA-HQ-OAR-2023-0072-0022 (2023) [hereinafter *Power Sector Trends TSD*].

Figure 1b. U.S. Electricity Generation by Source, 1950–2022



Data source: U.S. EIA, Annual Energy Review and Electricity Power Monthly, February 2023.

Figure 2. Average Capacity Factors for U.S. Fossil-fired Electricity Generators[155]



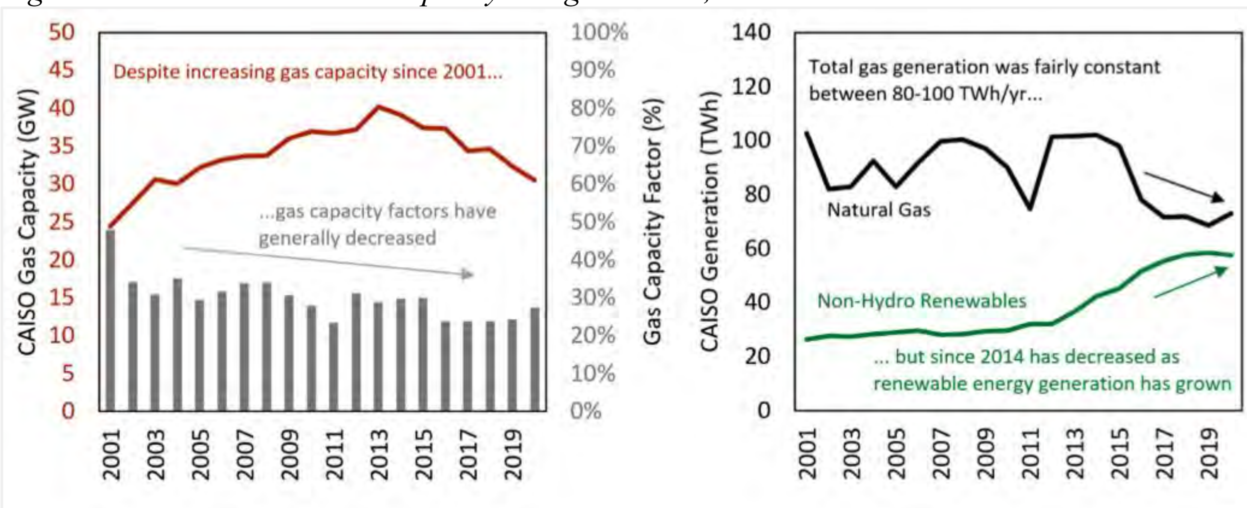
There has been a significant increase in methane gas and renewable generation in the U.S. power sector. Gas generation has increased from 601 GWh in 2000 to 1,689 GWh in 2022, while renewable generation grew from 357 GWh to 913 GWh respectively.[156] The expansion in generation capacity has also been notable for both sources. Since 2000, natural gas has added 426 GW of operating generation capacity and reached 497 GW of installed net summer capacity in 2022.[157] Renewables installed capacity has seen considerable growth, primarily from wind and solar resources. Between 2000 and 2022, renewable generation increased from 315 GWh to 815 GWh. In 2022, the share of renewable generation reached 22 percent, surpassing coal's 20 percent share. It is worth noting that coal generation is expected to fall even below nuclear within the next year.[158]

Overall, the trends in the electric power sector show an irreversible shift toward an electric power system dominated by gas and renewables, with significant increases in generation from these sources and reductions in coal-fired generation.

[155] EIA, *Table 6.07.A.*, *supra* note 152.
[156] EIA, *Electricity Explained: Electricity in the United States* (June 30, 2023), https://www.eia.gov/energyexplained/electricity/electricity-in-the-us.php.
[157] EIA, *Electric Generators Inventory, Form EIA-860M* (June 2023), https://www.eia.gov/electricity/data/eia860m/.
[158] EPA, *Power Sector Trends TSD*, *supra* note 154, at 4.

As coal-fired generation transitions to playing a minor role in total electricity generation and capacity, and more variable renewable energy technologies come online, gas-fired EGUs will move down the dispatch stack, leading to lower capacity factors.[159] This trend is visible in California's ISO region, where coal share in electricity generation is negligible. Since 2014, generation output from CAISO's natural gas fleet has decreased and been displaced by growing renewable energy output (Figure 3).

Figure 3. CAISO Natural Gas capacity and generation, 2001 to 2020[160]



B. EPA's Modeling of the Inflation Reduction Act Baseline

The IRA was signed into law by President Biden on August 16, 2022. It marks the most significant action Congress has taken on clean energy and climate change in the country's history. It "redefined American leadership in confronting the existential threat of the climate criss and set forth a new era of American innovation and ingenuity to lower consumer costs and drive the global clean energy economy forward."[161]

Section 60107 of the Act amends the Clean Air Act to add Section 135, called the Low Emission Electricity Program. Section 135(a)(5) directs EPA "to assess … the reductions in greenhouse gas emissions that result from changes in domestic electricity generation and use that are anticipated to occur on an annual basis through fiscal year 2031." Section 135(a)(6) directs EPA "to ensure that reductions in greenhouse gas emissions are achieved through the use of the existing authorities of this [Clean Air] Act, incorporating the assessment under paragraph (5)." Thus, EPA was directed to assess the new business-as-usual trend as shaped by the IRA—the

[159] *Id.* at 16.

[160] Cal. Pub. Util. Comm'n, *Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning* 6 (2021), *https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/cpuc-gas-upgrades-staff-paper-october-2021.pdf*.

[161] The White House, *Inflation Reduction Act Guidebook*, https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/ (last visited Aug. 2, 2023).

power sector emission reductions anticipated as a result of the IRA's large incentives—and then to set a new round of standards under the Clean Air Act taking that new baseline into account.

The IRA includes at least a $369 billion investment in climate change solutions and clean energy innovation, mainly through tax credits and deployment incentives for zero-carbon technologies.[162] Through these mechanisms, the Act focuses on accelerating deployment of clean energy and low-carbon technologies at the final stages of development.

While the IRA supports climate solutions for a variety of industries, many of its provisions relate specifically to the power sector. The IRA includes provisions such as funding for clean energy demonstrations, loans for clean energy projects and energy infrastructure replacement, grants and loans for rural clean electricity production and storage, funding for methane emissions reduction, authorization for offshore wind and other renewable energy leases, and funding for advanced nuclear energy.[163]

The IRA also includes tax credits for the production of electricity from renewable sources,[164] investment in renewable energy projects,[165] solar and wind facilities in low-income communities,[166] nuclear power production,[167] technology-neutral clean electricity investment and production,[168] investments in advanced energy projects,[169] production of clean energy components,[170] carbon dioxide sequestration,[171] and clean hydrogen production.[172]

For this proposal, EPA has developed and used a new baseline: the Post-IRA 2022 Reference Case.[173] The Post-IRA baseline has a considerably cleaner generation and capacity mix, lower system costs and prices, and significant reductions in air pollution compared with EPA's Pre-IRA 2022 Reference Case baseline.

EPA's findings that the IRA will accelerate the shift to cleaner generation, reduce electricity costs, and lower climate and air pollution are consistent with the broader literature of analysis completed on the emissions and energy impacts of the IRA.[174] In fact, EPA's Post-IRA baseline is well-aligned with the average (central) estimates across the literature, if even slightly more

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[162] *See* IRA, Pub. L. No. 117–169, 136 Stat. 1818 (2022), www.congress.gov/bill/117th-congress/house-bill/5376/text.
[163] *See id.*
[164] 26 U.S.C. § 45.
[165] *Id.* § 48.
[166] *Id.* §§ 48(e), 48E(h).
[167] *Id.* § 45U.
[168] *Id.* §§ 48E, 45Y.
[169] *Id.* § 48C.
[170] *Id.* § 45X.
[171] *Id.* § 45Q.
[172] *Id.* § 45V. *See also* The White House, *Clean Energy Tax Provisions in the Inflation Reduction Act*, https://www.whitehouse.gov/cleanenergy/clean-energy-tax-provisions/ (last visited July 17, 2023).
[173] EPA later released updated modeling on July 7, 2023. This included an updated baseline, an integrated proposal case, and "LNG Update" sensitivities. The main updates were the integrated proposal and sensitivities; there were minimal differences between the Post-IRA baseline and Updated baseline and no changes made to underlying assumptions or data sources.
[174] ERM, *Model Comparisons for Potential Impacts of the IRA on the U.S. Power Sector* (2023) [Attachment 3]

conservative, for the anticipated pace of clean energy deployment, transmission expansion, and carbon reductions seen with the IRA. As will be discussed in more detail, EPA's approach to model the IRA provisions, as well as the structural elements included in EPA's Integrated Planning Model (IPM) Platform v6 to proxy near-term supply and labor constraints for renewables and transmission timelines, results in a baseline that properly reflects both the significant financial incentives for clean energy deployment and the near-term obstacles to rapid deployment of these clean energy and grid technologies. EPA's modeled outcomes in its Post-IRA baseline are reasonable and an appropriate basis to build off of for its assessment of these proposed rules.

This Post-IRA baseline includes the IRA, as well as updates to other assumptions and additional finalized rules since the development of the Pre-IRA baseline. This includes the Good Neighbor Plan,[175] a revised power demand forecast that includes the incremental demand related to the finalized Light-Duty Vehicle GHG standards through model year 2026, adjustments to the turndown assumptions for select coal plants, updated CCS costs, and revised capacity values for energy storage.[176] This construction of the baseline—including reasonable projections of exogenous changes and the implementation of related legislation and regulations—comports with longstanding agency guidance[177] and is owed significant deference.[178]

EPA's approach to modeling the IRA is summarized below:[179]

- Incorporating the Clean Electricity Investment and Production Tax Credits (Sections 48E and 45Y) for new zero-emission resources and energy storage.[180]
    - These tax credits last until the later of 2032 or when emissions are 75 percent below 2022 levels, with EPA using 2021 levels (1,551 million metric tons or

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[175] While the overall impact of the Good Neighbor Rule on the baseline is minimal, we suggest EPA account in its final baseline for the limited implementation currently possible as a result of judicial stays and EPA's responsive administrative actions.
[176] EPA, *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case*, at Table 1-1 (2023) [hereinafter EPA, *Documentation*], https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf.
[177] Office of Mgmt. & Budget, Circular A-4 at 15 (2003) (A "baseline should be the best assessment of the way the world would look absent the proposed action…[which] may require consideration of a wide range of potential factors, including . . . evolution of the market, changes in external factors . . . , and changes in regulations promulgated by the agency or other government entities[.]"); EPA, Guidelines for Preparing Economic Analyses at 5-1 (2010) (defining a baseline as "the best assessment of the world absent the proposed regulation or policy action," while noting that this "does not necessarily mean that no change in current conditions will take place, since the economy will change even in the absence of regulation" and that "a well-specified baseline should address exogenous changes in the economy, industry compliance rates, other concurrent regulations, and behavioral responses").
[178] *Bluewater Network v. EPA*, 370 F.3d at 22 (Agency must "provide a reasoned explanation of its basis for believing that its projection is reliable. This includes a defense of its methodology for arriving at numerical estimates[.]"); *Melcher v. FCC*, 134 F.3d 1143, 1151-52 (D.C. Cir. 1998) (noting that judicial review should be "particularly deferential" when an agency is exercising its "predictive judgment," and noting that "'a forecast of the direction in which future public interest lies necessarily involves deductions based on the expert knowledge of the agency'") (quoting *FCC v. Nat'l Citizens Comm. for Broadcasting*, 436 U.S. 775, 813-14 (1978)).
[179] EPA, *Documentation*, *supra* note 176, at Section 3.10.1.
[180] *Id*. at Section 4.5.

    MMT) as a proxy in their post-IRA baseline. This emissions limit is not reached in the Post-IRA baseline and thus these credits are applied to all investments made in all run years during the 2028–2055 period.
    - We recommend EPA update its treatment of the 48E and 45Y tax credits to be based on the now-available 2022 emissions data, rather than the 2021 levels used as a proxy for this provision in this modeling.
- Modeling the energy community tax credit on top of the Clean Electricity Investment and Production Tax Credits (26 U.S.C. §§48E, 45Y) for wind, solar, and storage investments. This energy community tax credit provides a 10 percent bonus credit for these eligible investments based on the percent of land that qualifies as an energy community in each model region.[181]
- Modifying the short-term capital adder steps for renewable technologies between the 2028 and 2035 run years to reflect the impact of the Advanced Manufacturing Production Tax Credit (26 U.S.C. §45X).[182]
- Updating 45Q, or the Credit for Carbon Oxide Sequestration, to represent the increased monetary incentives for capture and geological storage of CO_2. A credit of $85/metric ton for geological sequestration and $60/ton for enhanced oil recovery (EOR) is provided for any plants that start construction or retrofit with CCS before January 1, 2033, and applied for the first twelve years of operation. This credit is applied as a reduction to the individual step prices in the CO_2 storage cost curves for plants that begin operating CCS in the 2028, 2030, and 2035 run years.[183]
- Allowing for the use of hydrogen as a fuel for the power sector, at a cost of $1/kg that is inclusive of the tax credits for clean hydrogen production (26 U.S.C. §45V).[184]
    - We recommend that EPA adjust the assumed cost of hydrogen to reflect expected transportation and storage-related costs associated with delivery. As discussed more in depth in part E of this section, there are additional structural updates EPA could make to further improve the representation of hydrogen fuel production for future modeling.
- Modifying the operation of and assumed retirement limits for nuclear plants as a proxy for the impacts from the Zero-Emission Nuclear Power Production Credit (26 U.S.C. §45U).[185]

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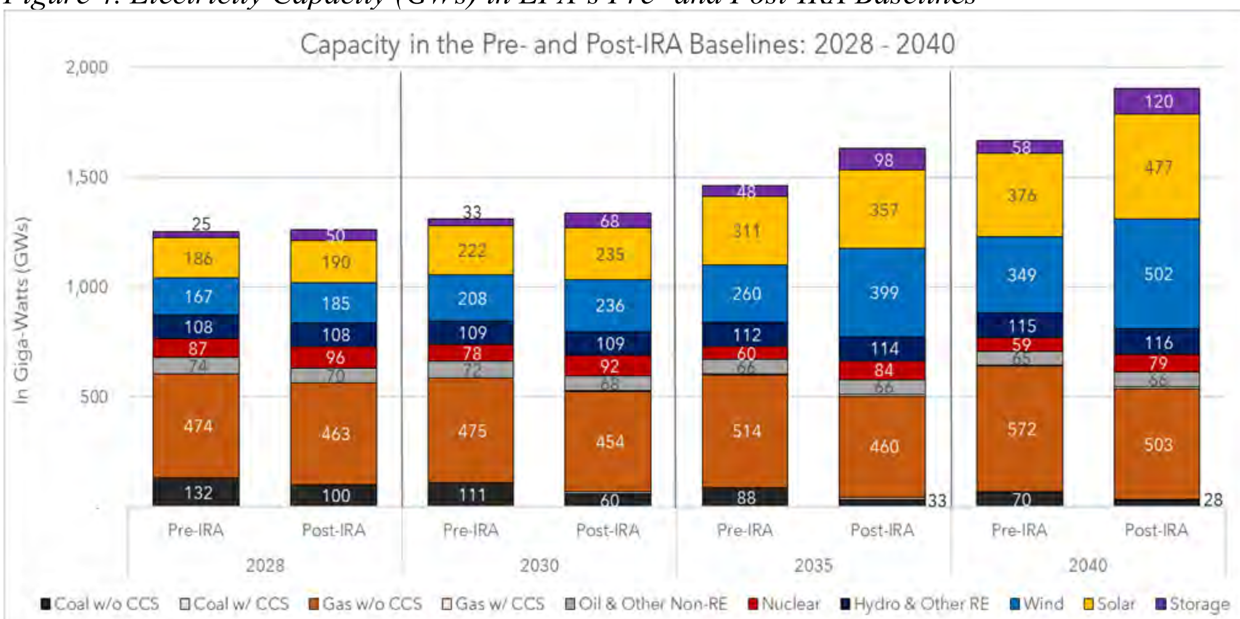
[181] The treatment of different technologies varies. In the Post-IRA baseline, EPA applies the 10 percent energy community tax credit to all new energy storage technologies (effectively assuming that developers will locate all storage in energy communities) and prorate the credit for wind and solar based on the share of total IPM regional land that qualifies as an energy community. *Id*. at Section 4.5.
[182] *Id*. at Section 4.4.3.
[183] *Id*. at Section 3.12. CCS projects starting operation in 2035 can be expected to commence construction before 2033 and thus be eligible for 45Q tax credits. For purposes of 45Q eligibility, IRS considers construction of a qualified facility or carbon capture equipment to have begun if the taxpayer satisfies particular requirements regarding physical work performed and expenses incurred. *See* Notice 2020-12 (Feb. 19, 2020). As part of these criteria, IRS requires construction efforts to proceed continuously, but deems any facility or carbon capture equipment to satisfy the continuity requirement if it is placed in service within six years from commencement of construction—much longer than the two-year difference between the 2033 commence construction deadline in 45Q and the 2035 run year, which happens to align with the proposed compliance deadline for new and existing baseload gas units that elect to deploy CCS.
[184] *Id*. at Section 9.5.
[185] *Id*. at Section 4.6.1.

Commenters are generally supportive of EPA's approach to modeling these different provisions of the IRA, with revisions as suggested above. The Post-IRA Baseline approach covers the key IRA provisions for the power sector and establishes a baseline that properly incorporates known and existing laws and regulations and ensures that the modeling projections reflect a best estimate of the future power system, given laws on the books today. We provide recommendations to further improve the representation of key technologies, as well as areas where assumptions could be updated, at the end of this section.

C. EPA's Modeling Finds that the Inflation Reduction Act Will Spur Greater Investment in Clean Energy Alternatives.

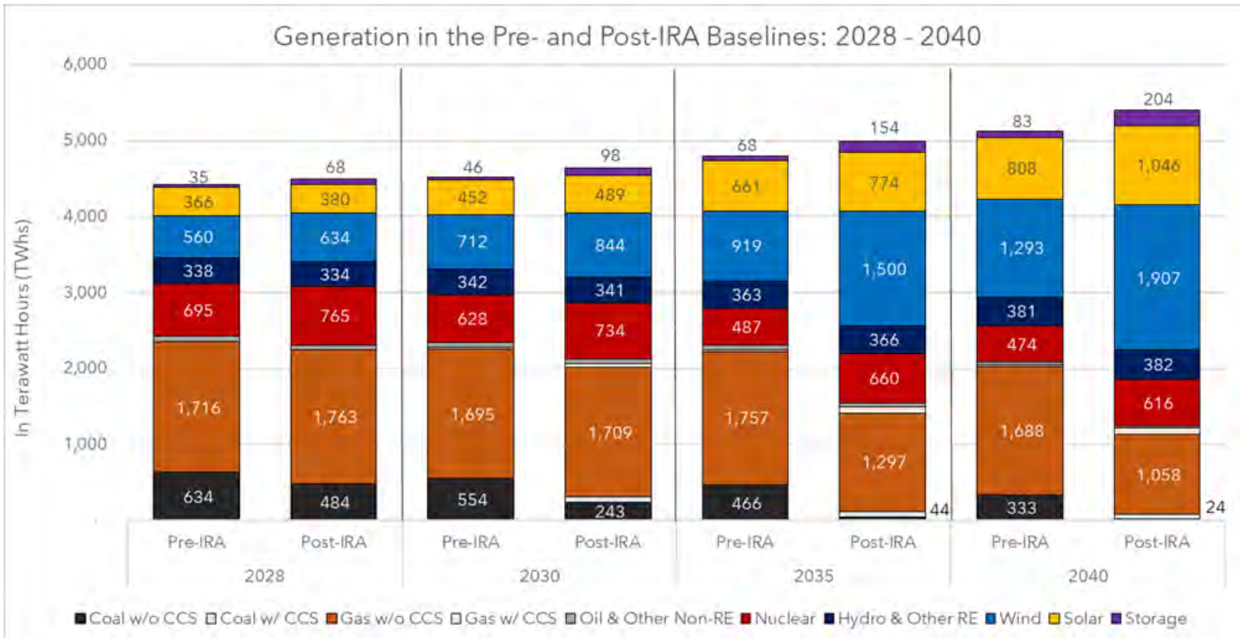
Compared to the Pre-IRA baseline, EPA's Post-IRA baseline sees lower levels of capacity, generation, and new investment in all forms of fossil-fueled power plants (coal, gas, and oil). Instead, the Post-IRA baseline has a greater retention of existing nuclear and stronger deployment of new wind, solar, and storage in all run years. (Figures 4 and 5)

Figure 4. Electricity Capacity (GWs) in EPA's Pre- and Post-IRA Baselines[186]



[186] NRDC, analysis of the published *System Summary Report (SSR) for the Pre-IRA 2022 Reference Case and Post-IRA Reference Case* (2023).

Figure 5. Electricity Generation in Terawatt-hours (TWhs) in EPA's Pre- and Post-IRA Baselines[187]



The inclusion of the IRA has a significant impact on the operational decisions for coal plant owners. In EPA's Post-IRA baseline, we see an additional 31 GW of coal retire by 2028, an additional 43 GW retire by 2030, and an incremental 35 GW of coal retire by 2040 compared to the Pre-IRA baseline. This is a 38 percent reduction in coal capacity in 2030 in the Post-IRA baseline compared to the Pre-IRA baseline. (Table 3)

[187] *Id.*

Table 3. Key Coal Statistics in EPA's Pre- and Post-IRA Baselines[188]

Total Coal (w/ and w/o CCS)	Case	2028	2030	2035	2040	2045
Coal Capacity (GW)	**Pre-IRA**	131.7	111.8	88.3	70.4	62.2
	Post-IRA	100.5	68.9	44.0	35.4	21.7
	Difference	**-31.2**	**-42.9**	**-44.3**	**-35.0**	**-40.5**
Coal Generation (TWh)	**Pre-IRA**	634	558	470	337	280
	Post-IRA	484	309	120	79	22
	Difference	**-150**	**-249**	**-350**	**-258**	**-258**
Avg. Coal Capacity Factor	**Pre-IRA**	55%	57%	61%	55%	51%
	Post-IRA	55%	51%	31%	25%	12%
	Difference	**0%**	**-6%**	**-30%**	**-29%**	**-40%**

In addition to the accelerated retirement of the coal fleet given the new and enhanced incentives for clean electricity resources, the coal remaining on the system starts to run significantly less by 2035. This reduction in utilization coincides with stronger deployment of new renewable and storage capacity, which reduces the need to dispatch higher marginal cost resources like coal. By 2035, the remaining coal fleet is running about 31 percent of the time, compared to 61 percent of the time in the Pre-IRA baseline. By 2045, this drops to just a 12 percent capacity factor in the Post-IRA baseline—compared to 51 percent in the Pre-IRA baseline. In total, coal generation in the Post-IRA baseline declines by 24 percent in 2028, 45 percent in 2030, 74 percent in 2035, and 77 percent in 2040 compared to the Pre-IRA baseline.

Gas-fired power plants see similar declines in utilization as more renewable energy is added to the system, displacing the need for higher marginal cost resources like gas and coal to meet demand. Even without the IRA, gas-fired plants saw declining capacity factors, with combined cycle plants reducing utilization from 65 percent capacity factors in 2028 and 2030 to 50 percent by 2050 in the Pre-IRA baseline. This reduction in utilization is accelerated with the IRA. While capacity factors are similar at 64 percent in 2028 and 2030 in the Post-IRA baseline, the average capacity factor for the combined cycle fleet falls to below 50 percent by 2035, to 41 percent by 2040, and down to 31 percent by 2050. Even in the baseline, the combined cycle fleet, on average, is running below the operating threshold EPA has proposed for its existing gas standard. Moreover, these modeling projections align with how operators intend to run their gas-fired units

[188] *Id.*

in the future, largely serving to fill in for increasing shares of intermittent renewable generation.[189]

EPA's finding that both coal and gas plants will be substantially impacted by the IRA is not unique. A study by Environmental Resources Management (ERM) analyzed the outcomes of five public studies modeling the impact of the IRA on power sector outcomes.[190] Across these studies, coal generation decreased by between 44 percent and 72 percent percent in 2030 (as compared to No IRA cases) and by 39 percent and 96 percent in 2035. There is no coal generation in one model by 2040 (Energy Innovation), which included not only the clean electricity tax credits but also modeled certain IRA provisions related to coal retirement and transition, such as the USDA Assistance for Rural Electric Cooperatives. All models studied by ERM also show declining generation from gas-fired power plants over the next two decades, consistent with EPA's own Post-IRA baseline.

The electricity system has seen large changes since the start of the 21st century. The market share of coal in the U.S. has declined from over 50 percent of the grid in the beginning of the 2000s to 20 percent in 2022—due to a combination of economics, aging coal units, and state and federal policies.[191] At the same time, utility-scale generation from wind, solar, and hydro has grown three-fold. Renewables are now the second-largest source of electricity in the U.S., beating out both nuclear and coal for the first time in 2022.[192] The passage of the IRA will only accelerate these forces and the shift away from fossil electricity in the U.S. in the next few years. EPA's modeling is consistent with the trends already seen in the electricity markets over the last two decades and industry expectations following the passage of the IRA.

In this regard, a recent analysis by The Brattle Group concluded that the 68 GW of planned coal retirements announced at the time of publication would likely be surpassed, based on a historical pattern of understated future coal retirements.[193] Low gas prices, declining costs of replacement resources such as renewable energy, and increased operations and maintenance costs at aging

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[189] *See, e.g.*, LS Power, *2021 Sustainability Report: Accelerating the Energy Transition* 42 (2022), https://www.lspower.com/wp-content/uploads/2022/07/2021-LS-Power-Sustainability-Report.pdf ("LS Power believes retention of certain natural gas facilities will help bridge the gap to a renewable energy future, responsibly."); SRP, *2022 Annual Report* 5 (2022), https://www.srpnet.com/assets/srpnet/pdf/about/2022-annual-report.pdf ("A top priority for SRP in making the transition to cleaner and renewable energy is maintaining reliability, which requires a balance of resources including renewables, battery storage and flexible natural gas generation. Gas generation is critical to filling in the gaps when intermittent resources are not available or cannot meet demand…"); DTE Electric, *2022 DTE Electric Integrated Resource Plan Summary* 14, https://dtecleanenergy.com/downloads/IRP_Executive_Summary.pdf ("According to the research, our customers want a diverse mix of energy generation sources going forward, with renewable energy leading the way, and natural gas supporting reliability.").

[190] ERM, *Model Comparisons for Potential Impacts of the IRA on the U.S. Power Sector* (2023) [hereinafter ERM, *IRA Model Comparisons*] [Attachment 3].

[191] EIA, *Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923)*, https://www.eia.gov/electricity/data/state/?src=email (last visited Aug. 2, 2023); EIA*, Electric Power Monthly: Table 1.1. Net Generation by Energy Source: Total (All Sectors) 2013–February 2023*, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_1_01 (last visited Aug. 2, 2023) [hereinafter EIA, *Table 1.1*].

[192] EIA, *Table 1.1*, *supra* note 191.

[193] Celebi et al., *supra* note 150, at 5-6 & fig. 4.

coal-fired plants are all expected to continue to contribute to the downward trend for coal.[194] Indeed, statements from utilities, coops, and independent power producers support a continuation of this trajectory.[195] For example, DTE plans to phase out coal by 2036, partly supported by IRA tax incentives for cleaner generation;[196] Minnesota Power intends to retire or repower its coal-fired EGUs by 2035;[197] PacifiCorp anticipates that it will retire or convert to gas all of its coal-fired EGUs by 2039, many well before;[198] Tri-State Generation and Transmission seeks to remove coal from its portfolio in some states by 2030, and in others by 2038;[199] and Vistra will likely retire most of its coal-fired EGUs by 2027.[200] Similarly, in announcing its 2022 Integrated Resource Plan (IRP), Georgia Power indicated that it would exit coal by 2028 at most plants, with the remaining coal-fired EGUs' fate pending before the state's utility commission.[201] Statements like these underscore how IPM's projections of business-as-usual reflect companies' own business expectations.

D. The Amount of Renewable Energy Deployment Under Both the Proposed Rule Scenario and the IRA Baseline Scenario is Reasonable and Does Not Rely on a Large-scale Build-out of Transmission.

Historic and current renewables deployment rates demonstrate that the amount of renewables projected to occur in both the Post-IRA baseline and the Proposed Rule case are reasonable. EPA properly has relied on these projections in concluding that affected units can fully comply with the proposed rules with no negative impacts on electric system reliability. In EPA's Post-IRA baseline, annual U.S. renewable builds are projected to average between 40 and 45 GW in most years; the historical record is 32.9 GW, with the U.S. Energy Information Administration (EIA) projecting annual renewable builds of 36.3 and 38.2 GW in 2023 and 2024, respectively.[202] The level of renewables deployment projected for the period when affected units will be complying with the rules in EPA's Baseline is only modestly higher than the amounts that are being deployed in 2023 and 2024. Given the large infusion of financial incentives for renewables in the IRA, the future modest increases during the rules' compliance periods are entirely justified as a basis for concluding that compliance is clearly achievable.

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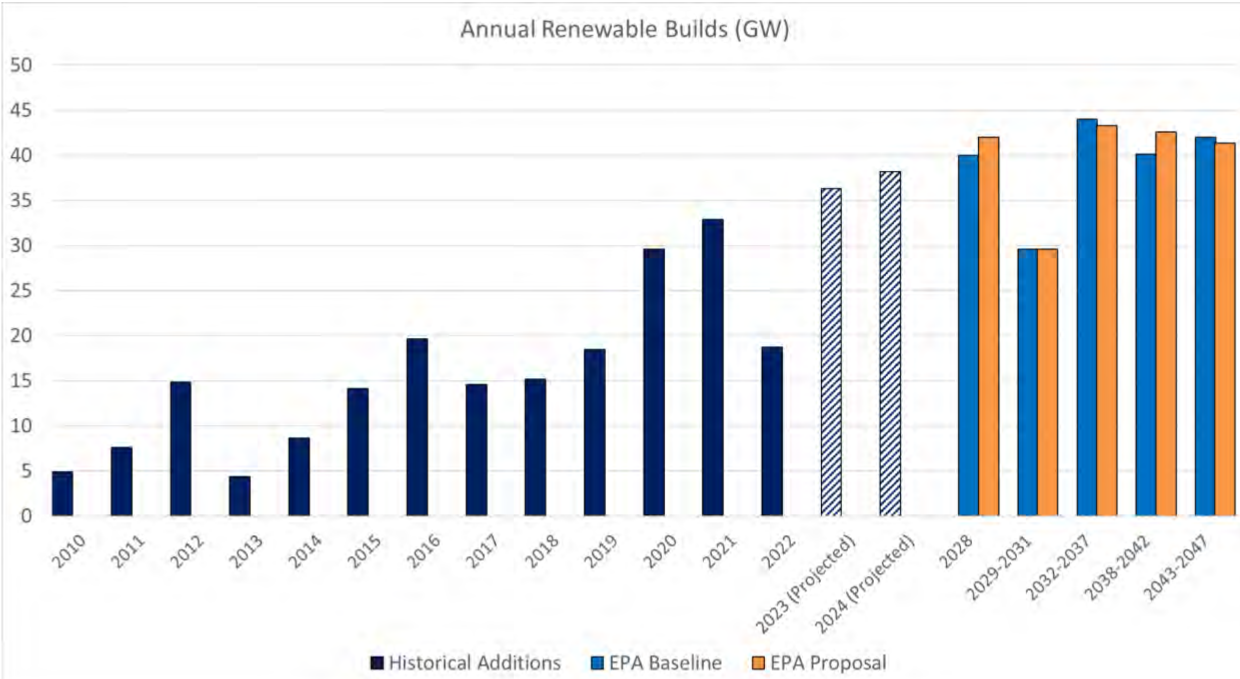
[194] *See id.* at 9-21.
[195] *See id.* at 25-27.
[196] *See id.* at 27-28.
[197] *See id.* at 31-32.
[198] *See id.* at 33-34.
[199] *See id.* at 36.
[200] *See id.* at 38.
[201] Georgia Power, *Georgia Power's transformational plan for state's energy future approved, helps ensure company will continue to meet needs of customers and state* (July 21, 2022), https://www.georgiapower.com/company/news-center/2022-articles/georgia-power-transformational-plan-for-states-energy-future-approved-helps-ensure-company-will-continue-to-meet-needs-of-customers-and-state.html.
[202] EIA, *Short-term Energy Outlook July 2023*, tbl.7e. U.S. Electric Generating Capacity (2023), https://www.eia.gov/outlooks/steo/.

Figure 6. Annual Renewable Builds, 2010–2022, projected through 2047[203]

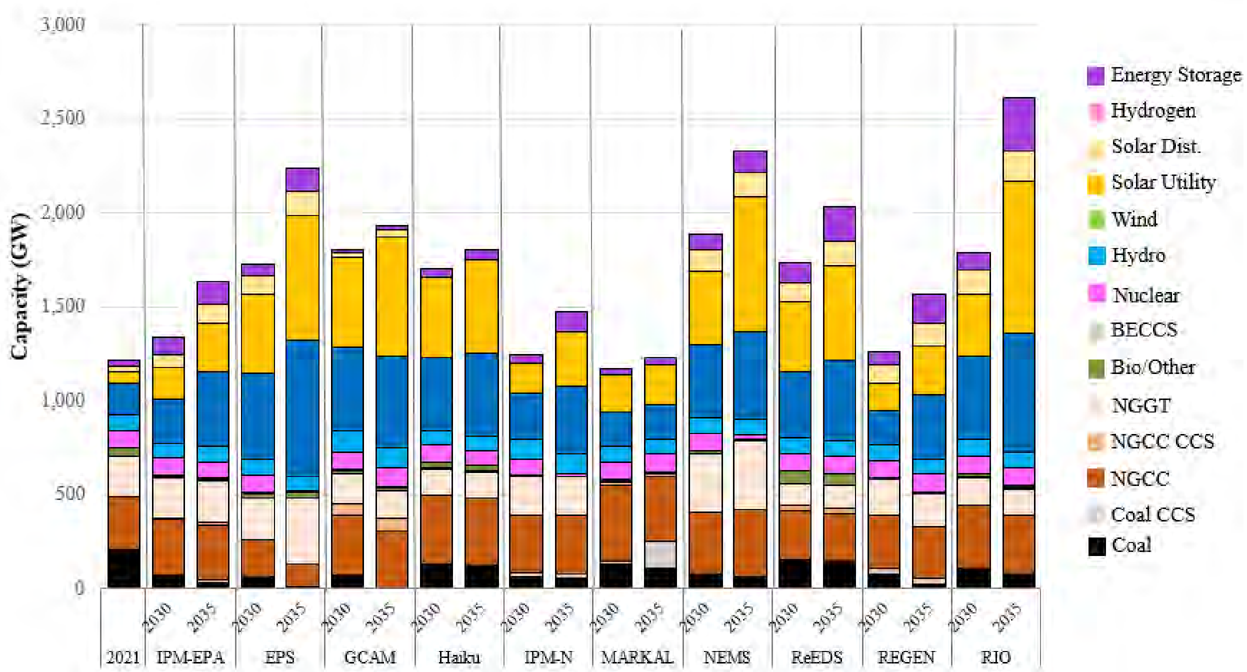


While the Post-IRA baseline does see higher levels of renewable energy deployment and generation than past EPA baselines, this Post-IRA baseline is well within the range of other models looking at the IRA. Figure 7 compares the capacity mix of 10 different models, all of which include key IRA energy provisions.[204] In 2030, between 381 and 978 GW of wind and solar are operating on the grid (up from 260 GW in 2021), with an average across the 10 models of 706 GW of wind and solar installed by 2030 with the IRA. EPA's Post-IRA baseline has a total of 472 GW of wind and solar operating in 2030, a level of deployment more conservative than most of the models analyzed. Growth in wind and solar capacity does pick up in EPA's Post-IRA baseline by 2035, but the projected growth is still below the average of all 10 models and well below some of the other models. In 2035, between 393 and 1,607 GW of wind and solar are operating on the grid, with an average across the 10 models of 1,103 GW. EPA's Post-IRA baseline has a total of 756 GW of wind and solar operating in 2035.

[203] EIA, *Electric Power Annual*; EIA, *Short-term Energy Outlook July 2023*, tbl.7e. U.S. Electric Generating Capacity (2023), https://www.eia.gov/outlooks/steo/; EPA, Power Sector Modeling, https://www.epa.gov/power-sector-modeling/analysis-proposed-greenhouse-gas-standards-and-guidelines.

[204] This includes 9 models detailed in John Bistline et al., *Emissions and energy impacts of the Inflation Reduction Act*, 380 Science 1324 (2023), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC10336889/pdf/nihms-1914379.pdf, as well as EPA's Post-IRA Baseline.

Figure 7. Comparison of Installed Capacity (GW) in 2030 and 2035 across 10 models, representing scenarios with the Inflation Reduction Act[205]



EPA's Post-IRA baseline deploys more renewable energy than past EPA baselines have due to significant shifts in the policy landscape from the passage of the IRA. This cleaner baseline is a product of EPA using appropriate assumptions and sound methodology, and is a reasonable reflection of new, historic legislation that provides an estimated $369 billion for clean energy and climate investments. In many ways, EPA's Post-IRA baseline is a conservative estimate of how the IRA may drive new investments in clean energy and accelerate the transition away from uncontrolled fossil fuels (see Figure 8, which show how EPA's Post-IRA baseline compares across the 10 models for share of generation from low-carbon resources). The more constrained growth in renewable energy under EPA's Post-IRA baseline, as compared to other models, may be driven, in part, by specific structural elements included in EPA's Platform v6, namely the inclusion of short-term capital cost adders. These short-term capital cost adders are explicitly designed to represent potential obstacles—like labor and supply constraints—to deploying levels of wind and solar additions well beyond historical levels. In this way, these adders serve as proxies for the potential barriers or obstacles to rapid growth of renewables, well beyond what has been seen historically, due to market and supply chain constraints.

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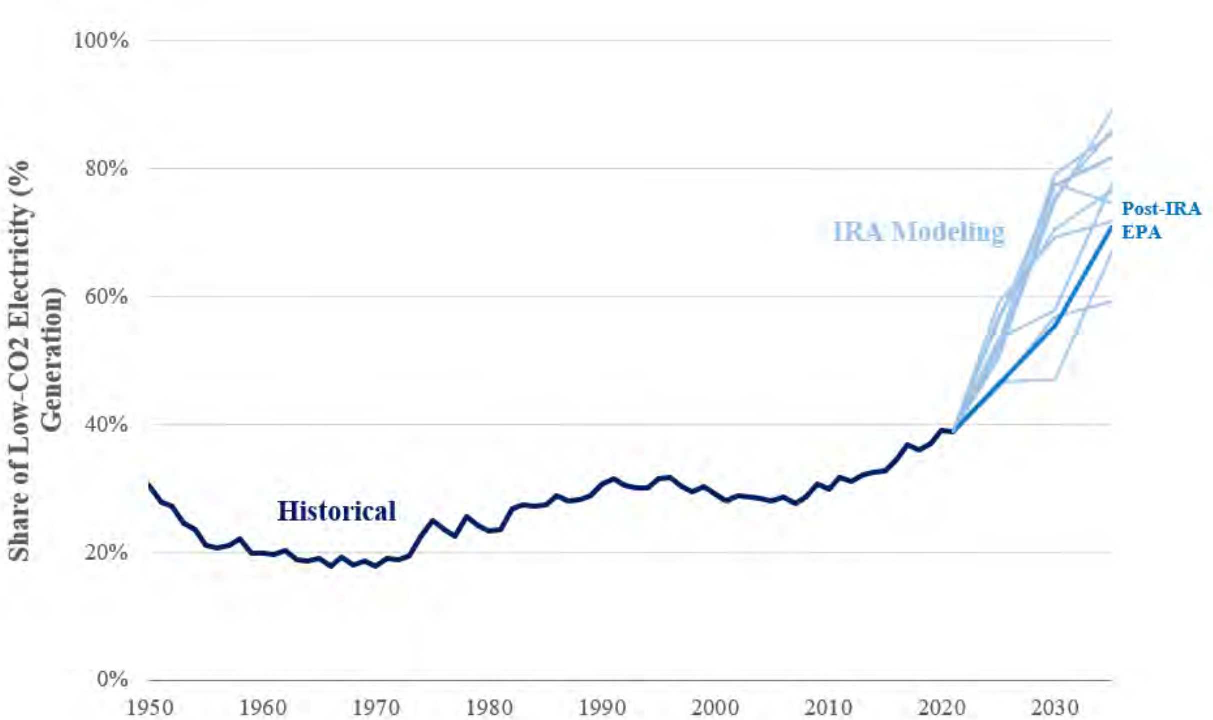
[205] John Bistline et al., *Emissions and energy impacts of the Inflation Reduction Act*, 380 Science 1324 (2023), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC10336889/pdf/nihms-1914379.pdf; EPA, Power Sector Modeling, https://www.epa.gov/power-sector-modeling/analysis-proposed-greenhouse-gas-standards-and-guidelines.

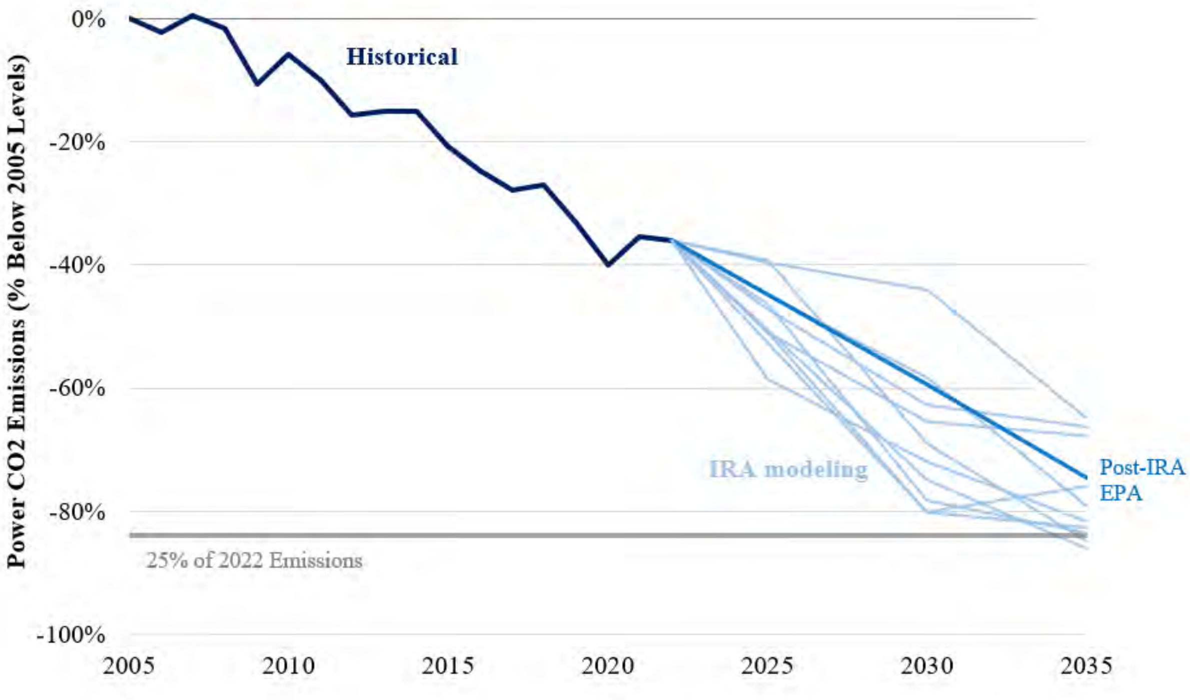
Figure 8. Share of low-carbon (renewable, nuclear, and fossil with CCS) electricity across 10 modeled scenarios of the IRA[206]



Consistent with EPA's baseline being more conservative than others on renewable energy growth and deployment, the Post-IRA baseline also sees smaller reductions in power sector CO_2 emissions with the IRA between 2025 and 2035 than other models. As shown in Figure 9, the Post-IRA baseline tends to show higher levels of power-sector CO_2 emissions through 2035 than most other models analyzed.

[206] John Bistline et al., *Emissions and energy impacts of the Inflation Reduction Act*, 380 Science 1324 (2023), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC10336889/pdf/nihms-1914379.pdf; EPA, *Power Sector Modeling*, https://www.epa.gov/power-sector-modeling/analysis-proposed-greenhouse-gas-standards-and-guidelines.

Figure 9. Percent reduction in CO_2 (from 2005 levels) across 10 modeled scenarios of the IRA[207]



As EPA notes in its documentation for EPA Platform v6, "EPA Platform v6 includes a short-term capital cost adder that kicks in if the new capacity deployed in a specific model run year exceeds certain upper bounds. This adder is meant to reflect the added cost incurred due to short-term competition for scarce labor and materials."[208] This adder applies to capacity built through 2035, representing an assumption that these supply chains would have by then had the time to grow in response to steady, growing demand for these technologies.

Based on EIA's short-term supply cost assumptions in the Annual Energy Outlook (AEO), the adder in IPM is modeled by utilizing three "steps," representing different levels of annual additions of any given technology. A certain amount of capacity can be built with no capital adder (Step 1); capacity built in a given year above this Step 1 level would incur additional capital costs (as a $/kilowatt (kW) cost), with these additional costs increasing incrementally as, or if, the model continues to build additional capacity in that year (i.e., Step 2 and 3). Each step is based off of a "base" amount, which represents the single highest level of annual capacity additions for that technology seen in the past 10 years, with Step 2 starting at 125 percent of the base amount in 2023.[209] In EPA's version, the width of these steps increases somewhat between 2023 and 2035 to represent the expected growth in domestic manufacturing capabilities due to the 45X manufacturing credit in the IRA.[210] Additional incremental costs are levied in EPA's Platform v6 when wind or solar additions reach around 150 percent of the base amount in 2028,

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[207] Sources cited *supra*, note 206.
[208] EPA, *Documentation*, *supra* note 176, at Section 4.4.3.
[209] EIA, *Model Documentation: Electricity Markets Module 2022*, at 70 (2022), https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/EMM_2022.pdf.
[210] EPA, *Documentation*, *supra* note 176, at Section 4.4.3.

around 160 percent of the base amount in 2030, and around 190 percent of the base amount in 2035.

EPA's Platform v6 includes both a detailed representation of the existing intra-regional transmission system, as well as the ability to endogenously build new transmission lines between certain regions. The ability to build new transmission lines is a feature first included in v6, with the change due to the "increased deployment of new renewable generation capacity that is at a significant distance from the load centers driving its deployment."[211] Allowing for the deployment of new transmission can result in a more economic deployment of new renewable capacity and allows IPM to co-optimize transmission and generation to meet capacity and energy needs.

New transmission can only be deployed starting in 2028. The model has 348 different existing transmission corridors between regions, of which expansion is only allowed in 268 of the corridors.[212] The cost of expansion varies, based on estimated likely voltage rating, line length, and terrain.[213] In EPA Platform v6, these costs range from $117 to $1,140/kW (2019$), using estimates of the power (MW) ratings for each transmission line to determine the total cost.[214]

While the model can endogenously build new transmission lines, it tends to build significantly less transmission than other models that include the IRA (*see* Figure 10). The transmission system grows under 5 percent total by 2035 (compared to 2021 levels) in the Post-IRA baseline. This is compared to other models that see up to a 25 percent increase in transmission capabilities by 2035. EPA's build out is also lower than or similar to historical trends: the transmission system has grown by about 1 percent annually over the last decade and about 2 percent annually between 1978 and 2020.[215] These lower transmission levels result from differences in the assumed cost and development timelines for new transmission, as well as differences in the treatment of new renewables and total level of renewables deployed between models. EPA's assumptions about transmission buildout are therefore conservative, and we support their use in modeling the baseline.

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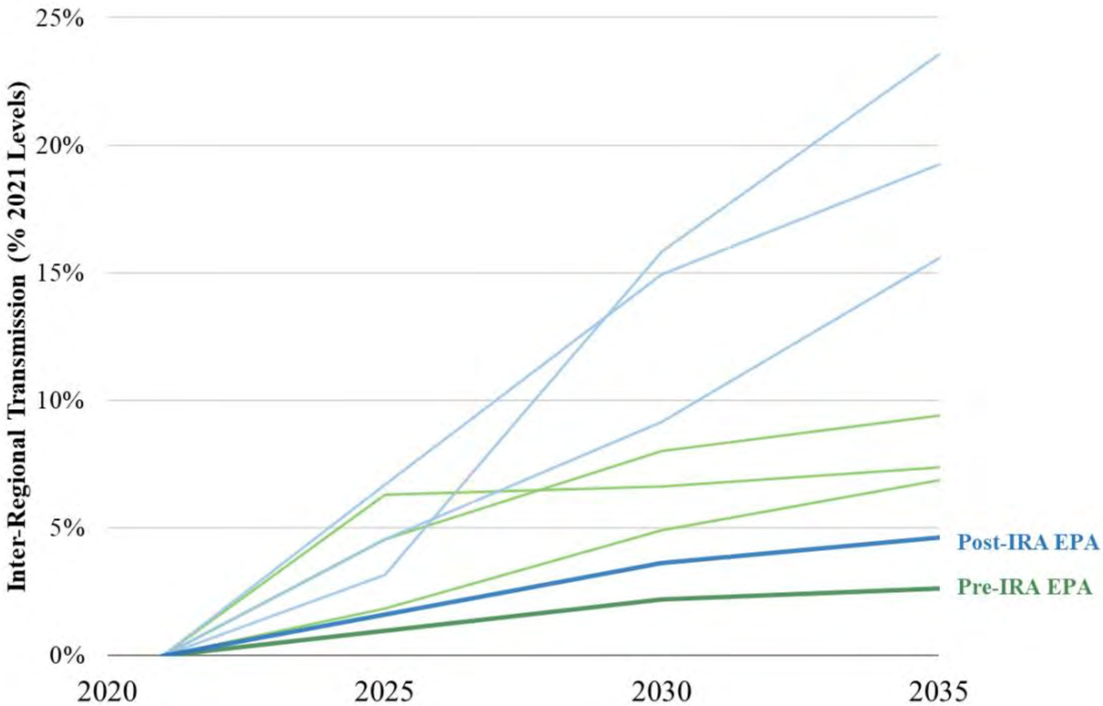
[211] EPA, *Documentation*, *supra* note 176, at Section 3.3.5.
[212] *Id.* at tbl.3-29.
[213] *Id.* at Section 3.3.5.
[214] *Id.* at tbl.3-29.
[215] ZERO LAB, Princeton Univ., *Electricity Transmission is Key to Unlock the Full Potential of the Inflation Reduction Act* 5 (2022), https://repeatproject.org/docs/REPEAT_IRA_Transmission_2022-09-22.pdf.

Figure 10. Transmission expansion in different models with and without the Inflation Reduction Act[216]



In addition, EPA's baseline projections of rapid deployment of battery storage capacity are conservative when compared to analysts' expectations. In the Post-IRA 2022 Reference Case, 50 GW of energy storage are on the grid by 2028, 68 GW by 2030, and 98 GW by 2035. By way of comparison, Wood Mackenzie estimates that 60 GW of grid-scale energy storage systems will be added between 2023 and 2027.[217] Further, "[Standard & Poor's (S&P)] Global Market Intelligence Power Forecast projects the U.S. will add over 85 GW of utility-scale battery energy storage capacity by 2035," on top of 10 GW currently deployed.[218] Those projections build on industry trends: installed utility-scale battery storage capacity quadrupled from the end of 2020 to the end of 2022.[219] Thus, levels of cumulative energy storage capacity in EPA's base case are lower than industry expectations and more than reasonable.

E. Recommended Adjustments to the EPA Baseline

EPA should consider implementing a few updates to its Baseline for future analysis in the docket. Some of these recommendations are related to more routine updates to underlying assumptions, while others involve more complex structural updates to the model itself.

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[216] John Bistline et al., *Emissions and energy impacts of the Inflation Reduction Act*, 380 Science 1324 (2023), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC10336889/pdf/nihms-1914379.pdf; EPA, Power Sector Modeling, https://www.epa.gov/power-sector-modeling/analysis-proposed-greenhouse-gas-standards-and-guidelines.
[217] *See* Wood Mackenzie, *US energy storage market continues to expand rapidly* (2023), https://www.woodmac.com/press-releases/us-energy-storage-market-continues-to-expand-rapidly/.
[218] *See* Tony Lenoir & Aude Marjolin, S&P Global Market Intelligence, *Charging up on battery energy storage 101, US market outlook* (2023), https://www.spglobal.com/marketintelligence/en/news-insights/research/charging-up-on-battery-energy-storage-101-us-market-outlook.
[219] *Id.*

1. Hydrogen Modeling

Given the importance of hydrogen co-firing at gas-fired power plants as a demonstrated technical basis for performance standards and a compliance option for affected units, the representation of the likely costs, availability, and impacts of hydrogen production and consumption on the power sector should be improved.

Currently, EPA models hydrogen as a fuel available at a fixed price of $1/kg (or $7.40/MMBTU) in the Baseline with no assumed delivery and transport costs. This cost decreases to $0.50/kg (or $3.70/MMBTU) in the Integrated Proposal case when Phase 2 of the new gas standard begins. This fuel is assumed to be "clean" and eligible for the highest subsidy under the 45V hydrogen production tax credit. While this would mean that much, if not all, of the eligible supply is derived from electrolysis with zero-carbon electricity, the current baseline - as well as the Proposal case - does not represent any growth in electricity to meet this hydrogen demand.

There are a number of modeling enhancements EPA should consider to improve the representation of hydrogen within IPM. As a simple adjustment, EPA should update its assumed hydrogen price to include delivery and transportation costs for hydrogen fuel, aligning the assumed production and transportation, delivery, and storage costs for electrolytic, green hydrogen with the broader literature on expected future costs. As an example, in the alternative IPM modeling discussed later in these comments, we use a subsidized cost of $3/kg in 2025, declining to a subsidized cost of $2/kg in 2035. There is a discussion of the existing literature on likely costs of hydrogen fueling and infrastructure in Section IX (Hydrogen Co-firing).

Given the impacts of electrolytic hydrogen on electricity load and capacity needs, EPA should work with ICF to implement structural changes that can incorporate these impacts into IPM. This could include incorporating a "power-to-fuel" module that would allow the model to endogenously optimize hydrogen demand. This could be similar to how ICF's Gas Markets Module is used in conjunction with IPM to determine gas consumption and prices in the power sector in EPA's v6 IPM. The model could optimize the deployment of both electrolyzers and generating capacity to produce hydrogen fuel for the power sector (with static representation of hydrogen demand from other end uses), determining the least-cost build out of capacity to meet energy needs, including any hydrogen fuel needs for the power sector itself. This would ensure that EPA is capturing the upstream impacts of any hydrogen production driven by policy (such as the IRA) or additional regulatory action, as is contemplated in this proposal.

2. Other Updates to Assumptions

EPA should also update sources for key assumptions to reflect more recent and up-to-date projections of technology performance and cost, electricity demand, and natural gas prices.

EPA should update its platform to reflect the more recent versions of key sources, including by:

- Moving to EIA's AEO 2023 for demand (current version uses AEO 2021 with modifications for vehicle standards through model year 26).[220]

[220] EIA, *Annual Energy Outlook 2023* (March 16, 2023), https://www.eia.gov/outlooks/aeo/.

- Moving to NREL's Annual Technology Baseline (ATB) 2023 for renewable energy and storage costs (current version uses NREL ATB 2021).[221] We would also recommend that EPA include longer-duration options, like 10 hour storage. This duration is included in ATB 2023.
- And incorporating any other updates that have been released for current sources in EPA Platform v6.

The regulated industry—and indeed the power sector as a whole—has been undergoing and continues to undergo a significant transition as older coal-fired power plants retire and gas-fired power plants operate less to support an increasingly renewable grid. In passing the IRA, Congress acted clearly to accelerate those trends as well as incentivize deployment of clean fuels and pollution controls on the remaining fossil fuel-fired fleet. With the few adjustments as described above, EPA properly models the anticipated future operation of the regulated source category irrespective of this proposal.

F. NRDC Baseline Modeling Shows Similar Outcomes

NRDC has utilized IPM to assess the impact of environmental standards in the power sector for more than a decade. The NRDC-IPM Base case includes many of these recommendations. The baseline case that accounts for finalized federal, state and regional energy policies as of April of 2023, including the IRA. Parties formulated its analysis based on electricity demand and fuel price assumptions taken from the EIA's 2023 AEO, with technology costs taken from multiple sources including EPA v6 Post-IRA 2022, the National Renewable Energy Laboratory's (NREL's) ATB 2022, and AEO 2023. It also incorporates 10-hour storage options and higher hydrogen prices that account for delivery-related costs and better match the literature on expected future hydrogen production costs. *See* Appendix C for additional details on the assumptions.

Generally, the results of the NRDC Baseline are similar to EPA's Post-IRA Baseline. CO_2 emissions are somewhat lower in all years between 2028 and 2040 (between 13 and 18 percent below EPA's Post-IRA Baseline levels; *see* Table 4). This is due to a larger build-out of renewables (specifically solar) and storage, which results in less new gas capacity added and lower utilization of the gas fleet (Table 5). While there is lower total gas capacity and generation, coal capacity and generation are similar between the two Baselines. In total, the NRDC Baseline has slightly fewer coal retirements until 2040, with another 8 GW of coal retrofitting with CCS by 2030 due to favorable economics with the 45Q tax credit. Total levels of fossil with CCS are similar, with NRDC's baseline seeing greater investment in coal with CCS, but reduced retrofits of gas combined cycle capacity with CCS. This result is expected given the use of the more recent sources for technology and fuel costs, which project slightly lower costs for renewable projects and higher gas prices, due to the inclusion of higher gas demand from non-power sector end-uses like LNG exports. These findings are also consistent with some of the high-level trends seen in EPA's own LNG update sensitivity cases that updated LNG demand to match AEO2023 (the same source used for NRDC's Baseline). In total, these differences in investments over the

[221] NREL, *2023 Electricity ATB Technologies and Data Overview*, Annual Technology Baseline, https://atb.nrel.gov/electricity/2023/index (last visited Aug. 2, 2023).

next two decades - when paired with the incentives in the IRA - result in slightly lower system costs under the NRDC's IPM Baseline as compared to EPA's Post-IRA Baseline (Table 6).

Table 4. Emissions under EPA and NRDC IPM Baselines (2028 to 2040)

National Emissions	Modeling Scenario	2028	2030	2035	2040
CO2 (million metric tons)	EPA IPM (Post-IRA)	1,222	972	608	481
	NRDC IPM	1,002	795	527	402
NOx (million tons)	EPA IPM (Post-IRA)	0.46	0.37	0.21	0.16
	NRDC IPM	0.44	0.37	0.24	0.15

Table 5. Capacity under EPA and NRDC IPM Baselines (2028 to 2040)

	Capacity (GW)	2028	2030	2035	2040
EPA	Coal	100	60	33	28
	Coal with CCS	-	9	11	8
	Gas CC	307	299	295	295
	Gas CT	156	156	164	207
	Gas with CCS	-	7	10	10
	Other	73	70	69	69
	Nuclear	96	92	84	79
	Hydro	102	104	108	110
	Wind	185	236	399	502
	Solar	123	161	263	360
	Storage	50	68	98	120
NRDC	Coal	93	61	34	18
	Coal with CCS	10	18	18	8
	Gas CC	292	293	295	293
	Gas CT	140	152	159	159
	Gas with CCS	1	4	4	4
	Other	58	58	56	51
	Nuclear	93	84	61	51
	Hydro	105	105	105	105
	Wind	199	254	397	454
	Solar	200	237	343	532
	Storage	60	72	112	187

Table 6. Total System Costs Under the NRDC and EPA Baseline (2028 to 2040)

Total System Costs	Modeling Scenario	2028	2030	2035	2040
Total Costs (billion $)	EPA IPM (Post-IRA)	$ 131.5	$ 125.2	$ 127.6	$ 136.8
	NRDC IPM	$ 131.5	$ 124.7	$ 119.8	$ 135.3

These comparative results between NRDC and EPA's Baseline support the reasonableness of the recommendations made by the Commenters above on EPA's Baseline. NRDC's Baseline incorporates many of the suggestions, using more recent vintages of key assumption sources like EIA's AEO and NREL's ATB, adding additional durations of battery storage, and modifying hydrogen prices to reflect additional costs associated with delivery. These changes result in a baseline with greater—but still reasonable—levels of renewable and storage deployment, less investment in and generation from gas-fired power plants, similar levels of coal retirements, similar investment in fossil with CCS, lower carbon emissions, and lower system costs over the next two decades.

V. Pollution Controls for GHGs from Fossil Fuel Fired Power Plants

West Virginia spoke favorably of traditional pollution controls like clean fuels and end-of-the stack scrubbers and controls. EPA appropriately focuses on these types of pollution control systems to set standards. The two controls that can eliminate nearly all GHG emissions from fossil fuel-fired EGUs at reasonable cost are CCS and low-GHG hydrogen co-firing. In this section, Commenters provide an overview of the state-of-the-art of these two technologies, with more detailed Appendices attached.

A. Carbon Capture and Sequestration is Adequately Demonstrated and Cost Reasonable for Long-Lived Coal-Fired Power Plants and Baseload Gas-Fired Power Plants

Post-combustion CCS was first determined to be adequately demonstrated and cost reasonable for new coal-fired EGUs in 2015. Since that time, the technology has become even more tested, proven, and deployed, and costs have come down. The technology is ripe to form the basis of standards for existing coal-fired EGUs requiring compliance with a CCS-based limit by 2030 for those plants that will continue to operate for eight years or more. It is also available and cost-reasonable for new baseload gas-fired power plants and large, baseload existing gas-fired power plants.

Commenters appreciate that the Administration is also putting significant emphasis on enabling safe and equitable deployment of CCS, where the affected sources choose to utilize the technology to comply with performance standards. For example, on July 10, 2023, DOE announced 16 projects across 14 states to receive significant funding to provide locally-tailored technical assistance and enhanced stakeholder engagement around carbon management technologies. The aim of the projects is to foster close engagement with communities affected by current and proposed CCS infrastructure with a strong emphasis on public engagement activities and community protections.

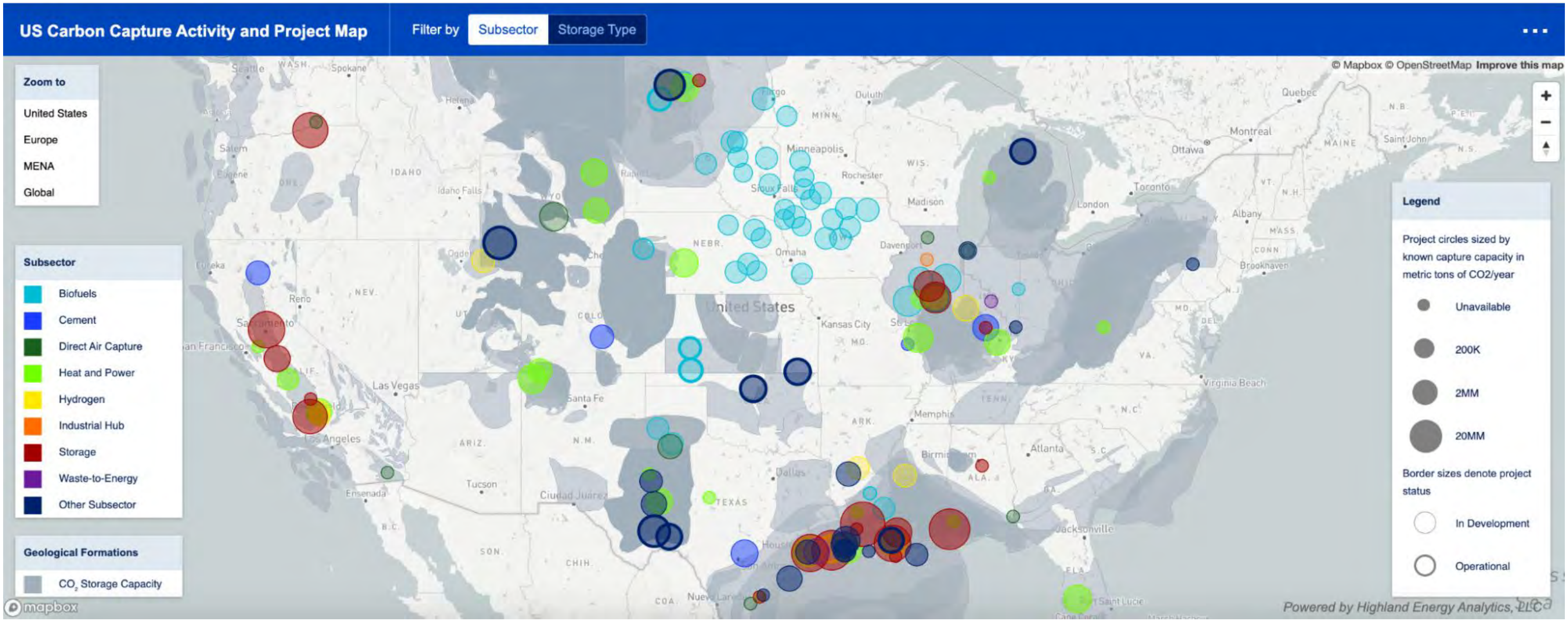
In Appendix A, we describe in detail the robust record supporting adequate demonstration of CCS: several examples of existing carbon capture projects in the power sector, at commercial and pilot scale, recently issued CCS permits, large-scale Front-End Engineering Design (FEED) studies, vendor information and deployment of the technology in other industries, with learning that can be transferred to the power sector. Here, we provide a brief summary. There are no technical barriers to CCS deployment in the power sector; there has just been limited deployment because to date there has been no requirement to meaningfully control carbon from this sector. When EPA set standards based on sulfur scrubbers in the 1970s, there were only three units in operation and one vendor for the technology, yet with standards in place, the technology was successfully deployed, costs declined further, and sulfur scrubbers became the industry standard and removed nearly all sulfur emissions from coal plants.

As described in more detail in the attached Appendix A, at least thirteen vendors have done significant testing and offer carbon pollution controls for coal and gas-fired power plants.
CCS has been installed and proven on two large-scale coal-fired power plants; and carbon capture is currently installed and operating on three coal-fired power plants in the United States (AES Warrior Run, AES, Shady Point, and Searles Valley Minerals). Integrated commercial

CCS demonstration on a power plant includes SaskPower's Boundary Dam Unit 3 CCS facility, which began operation in 2014 and has captured and sequestered over 5 million tons of CO_2 thus far. The Bellingham natural gas combined cycle (NGCC) power plant demonstrated post-combustion capture from 1991 to 2005 capturing 85 to 95 percent of its CO_2 emissions. In the past few months, two permits for CCS projects were issued to two existing NGCC power plants—Deer Park and Baytown—while two more permit applications were submitted, one for Quail Run NGCC and another for a coal-fired power plant, Milton R. Young. Meanwhile, Commenters are tracking 6 proposed CCS projects on coal-fired EGUs and 17 on gas-fired EGUs in the U.S. These include nine IRA-supported FEED Studies which will support the development of community-informed integrated CCS projects. The projects are geographically diverse and will capture 90 to 95 percent of CO_2 emissions utilizing capture technology from Honeywell, Mitsubishi Heavy Industries (MHI), Membrane Technology and Research, Inc., Linde-BASF, and ION Corporation.

Additionally, vast experience with CCS deployed in other industrial settings is relevant to application at EGUs. Most commercially available carbon capture technologies are easily adapted to different upstream facilities. What matters is the CO_2 concentration of the source gas, the type of impurities contained in it and its pressure and temperature. Carbon scrubbers are designed to accommodate a variety of concentrations, pressures and temperatures and regardless of the source, but other pollutants must be removed or the source gas will degrade the scrubber solvent. Therefore, the multiple commercial CO_2 capture facilities in the industrial sector (hydrogen, iron and steel, ethanol, fertilizer, and chemical production, natural gas processing, and oil refining) have developed technology and learnings that are transferable to the EGU source category. This includes two offshore operations in the North Sea (Sleipner and Snøhvit), which have been capturing a million tons of CO_2 a year for 27 and 15 years respectively, as well as the Quest CCS facility operated by Shell, which has captured and successfully sequestered more than 7 million tons from the Scotford Refinery since 2015. CATF is currently tracking 177 early-stage U.S.-based CCS projects of varying sizes and in various sectors, as seen in the map on the next page and in the spreadsheet included as Attachment 10.

Figure 11. Marking location, size and industry of CCS projects in development[222]



[222] *U.S. Carbon Capture Activity and Project Map*, CATF, https://www.catf.us/ccsmapus/ (last visited Aug. 7, 2023).

There are currently 5,000 miles of pipelines carrying CO_2 in the United States. Developers are currently seeking permits for multistate projects in the Upper Midwest, which would collectively comprise over 3,600 miles of new pipeline for carbon capture from ethanol plants. At the same time, PHMSA has initiated a new rulemaking to strengthen oversight of CO_2 pipelines and protect communities. Meanwhile, the National Energy Technology Laboratory (NETL) has released a CCS Pipeline Route Planning Database, which provides critical insights into the complex social, environmental and regulatory variables that will be encountered during pipeline projects. The database will assist in identifying optimal pipeline routes that are not only technically viable but also socially and environmentally responsible. The CO_2 pipeline network will be built out over the coming years, primarily to accommodate industrial applications of CCS. In the near term, flexible infrastructure development that considers connecting CO_2 assets with future utilization opportunities, strategic co-location with industrial clusters, and integrated planning with other carbon management infrastructure could help unlock CCS potential across the U.S.[223] Some estimate that irrespective of this rule, the CO_2 pipeline network will grow to 66,000 miles by 2050. However, the long-lived, highly polluting power plants subject to a CCS-based standard pursuant to this rulemaking can choose to tap into this growing network to transport CO_2 to sequestration offtake.

Carbon dioxide has been injected and stored in deep geologic formations at the commercial scale since the 1970s. The U.S. has widespread and abundant geologic storage options in deep saline aquifers. Geologic storage of CO_2 is widely available to reduce carbon emissions from fossil fuel-fired power plants and other large point sources. The DOE Carbon Sequestration (NATCARB) Atlas estimates a median storage potential of over 8,000 gigatons (GT) in saline formations in the U.S., which are spread across multiple sedimentary basins. Storage is regulated under EPA's Underground Injection Control authority, and monitored under Clean Air Act Greenhouse Gas Monitoring and Reporting requirements. Storage opportunities are well-dispersed and within reasonable distance of coal- and gas-fired power plants across the country. Additionally, significant saline storage potential has been identified in the offshore Mid-Atlantic region.[224]

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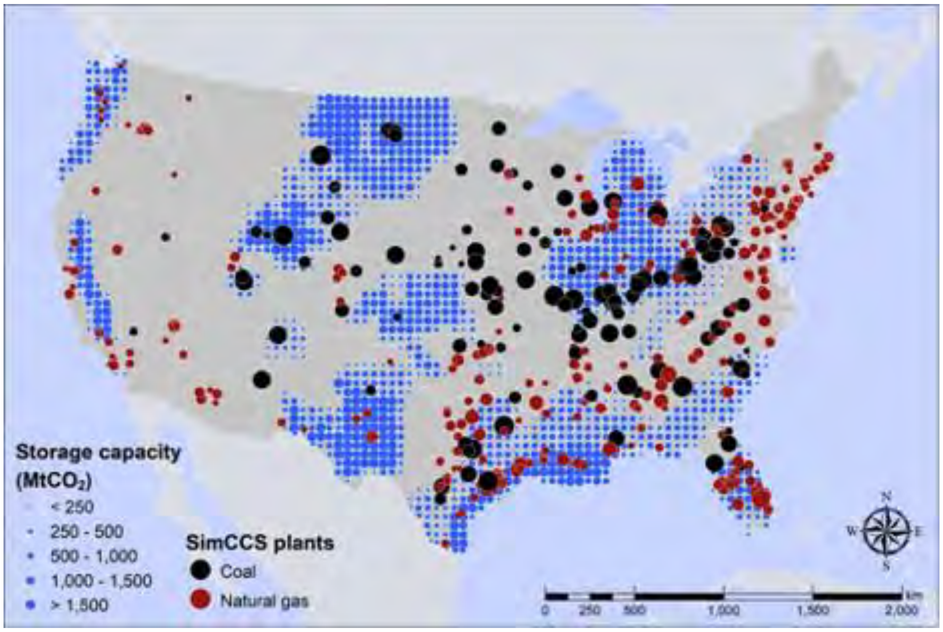
[223] Nat'l Acad. Sci., Engineering, & Med., *Carbon Dioxide Utilization Markets and Infrastructure: Status and Opportunities: A First Report* (2023), https://doi.org/10.17226/26703.

[224] To assure that operators of CO_2 injection sites have strong incentives to design and operate CO_2 sequestration sites to achieve safe, permanent sequestration, NRDC opposes limitations on liability and will advocate against such policies should they be proposed. NRDC also supports and will advocate for strong bonding requirements.

Figure 12. Overlaying existing coal and gas-fired power plants on available geologic storage[225]



In a conservative analysis, a recent report found that *all* existing fossil fuel-fired power plants without retirement dates before 2030 and operating at 30 percent capacity factor could capture, transport and store all of their climate pollution in saline formations through an optimized pipeline network for less than \$87/tCO_2.

DOE has recently updated its cost analysis for CCS projects for new and existing coal and gas-fired power plants. It relies on the latest carbon capture technology available and updated transportation and storage costs. The analysis includes sensitivities for higher levels of capture, various capacity factors, and retrofit difficulty. Commenters have utilized DOE-developed worksheets to analyze a variety of amortization timeframes, capacity factor thresholds, unit and plant size, and the impact of the increased IRA 45Q tax incentive. Generally, the abatement cost of CCS for coal plants is \$5/MWh of generation or \$6/ton of CO_2, new gas plants is \$3.5 to \$6.4/MWh of generation or \$11 to \$19/ton of CO_2; and for existing gas plants is \$5.6 to 8.6/MWh of generation or \$18 to 26/ton of CO_2. These costs are discussed more fully in Appendix A and a variety of sensitivities are discussed in Section VI. For those long-lived coal plants and baseload gas plants, CCS is well within the range of costs that have been found to be reasonable over and over again for prior Clean Air Act rulemakings.

Carbon capture is a CO_2 scrubber akin to the sulfur scrubbers that have been successfully deployed in response to the driver provided by the technology-forcing and forward-looking design of the Clean Air Act. CCS is far more proven and cost effective than sulfur scrubbers were when they first set the basis of standards. The pollution control is ripe to serve as the basis of Section 111 standards.

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[225] Carbon Solutions, *National Assessment of Natural Gas Combined Cycle (NGCC) and Coal-fired Power Plants with CO2 Capture and Storage (CCS)* (2022) [Attachment 11].

B. Low-GHG Hydrogen Co-firing is the Best System of Emission Reduction for New Low- and Intermediate-Load Gas-Fired Power Plants

Low-GHG hydrogen co-firing is the BSER for new low- and intermediate-load gas-fired power plants. Simple cycle turbines are likely to be used for low-load power plants due to their ability to quickly reach maximum power after startup. While EPA expresses concern on the ability for new simple cycle turbines, which are likely to be used for low-load power plants, to co-fire higher percentages of hydrogen, and whether manufacturers will focus research efforts on developing these turbines, EPA notes in the Hydrogen technical support document (TSD) that the "combustion turbines currently capable of co-firing greater than 30 percent hydrogen by volume are generally simple cycle turbines that utilize [wet-low emissions] or diffusion flame combustion."[226] Additionally, EPA cites comments from Constellation Energy explaining that "the newer simple cycle turbines can blend up to 25–30% hydrogen by volume without modification."[227] Given the ability of *current* simple cycle turbines to blend ratios of up to 30 percent hydrogen by volume, there can be no reasonable concern about the availability of *new* turbines that can co-fire hydrogen at low loads.

For intermediate-load turbines, hydrogen co-firing technology is adequately demonstrated, and new hydrogen projects that upgrade or retrofit turbines to blend hydrogen are plentiful. As EPA thoroughly covers in its TSDs, several of the largest turbine original equipment manufacturers (OEMs) such as General Electric (GE), Siemens Energy, and MHI currently offer turbine models that can co-fire large amounts of hydrogen.[228] These manufacturers are developing turbines that can operate on 100 percent hydrogen by approximately 2030. Indeed, GE already has two turbine models that can operate on 100 percent hydrogen.[229] Given that the 11 engines from GE, Siemens, and MHI cited in EPA's TSD cover approximately 90 percent[230] of the market, hydrogen-ready turbines will be widely available by 2030. And EPA cites nearly 20 new or existing hydrogen gas turbine demonstration projects. These projects demonstrate that the market is rapidly moving toward including co-firing at increasing hydrogen volumes, even absent federal regulation, and that the technology is adequately demonstrated.[231]

These projects and demonstrations also coincide with key developments in hydrogen production and infrastructure buildout. Together, funding authorized by the IIJA and the IRA will invest billions of dollars in hydrogen production and infrastructure and will spur even more private investment. Most notably, the DOE will invest $8 billion in 6 to 10 regional clean hydrogen hubs

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[226] *See* EPA, *Technical Support Document: Hydrogen in Combustion Turbine Electric Generating Units*, Docket ID No. EPA-HQ-OAR-2023-0072-0059, at 5 (2023) [hereinafter *Hydrogen TSD*], https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0059.
[227] *Id.* at 9.
[228] *Id.* at 5-6.
[229] *Id.* at 7.
[230] Envision, *Gas Turbine Manufacturers Market Share*, Envision Intelligence (Oct. 10, 2017), https://www.envisioninteligence.com/blog/gas-turbine-manufacturers-market-share/ (Note: Mitsubishi Heavy Industries was known as Mitsubishi Hitachi Power Systems at the time of this article.).
[231] *See Essex Chem. Corp.*, 486 F.2d at 433-34 ("An adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."); *Portland Cement Ass'n*, 486 F.2d at 391 (ruling EPA "may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry").

over the next 5 years. The IIJA directs DOE to select hubs that will include demonstrations of a variety of production methods, including renewable powered electrolysis and nuclear-powered electrolysis. DOE is also directed to select hubs that will demonstrate a range of end use applications, including use cases in electric power. Hubs intend to operationalize the midstream infrastructure necessary to transport and store hydrogen safely and at large volumes, including by supporting the development of salt-cavern storage and hydrogen pipelines.

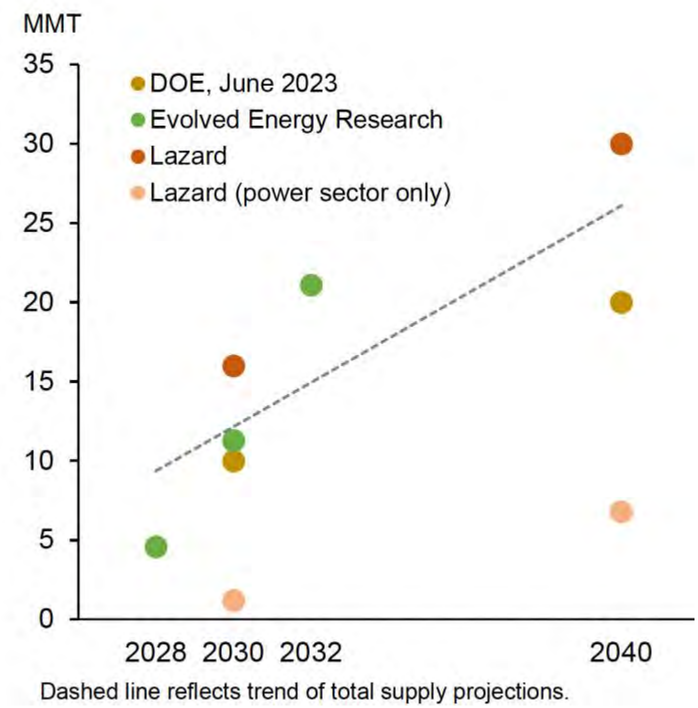
CATF has published a comprehensive map of the 22 publicly announced, active Regional Clean Hydrogen Hub applications across the United States.[232] We anticipate that hubs will be selected in diverse regions across the country, spanning multiple states. Alongside the hubs DOE selects for funding, the Hubs program received significant interest from over 79 project developers spanning 47 of the 50 U.S. states, 33 of whom were encouraged to submit a full application to the DOE in December of 2022. Many applicants have hundreds of industry partners signed on as producers, midstream infrastructure providers, and offtakers. Many hubs have expressed interest in continuing to develop portions of their projects whether they are selected by DOE for funding or not. The hydrogen production tax credit in the IRA will further spur hydrogen production. And in July 2023, DOE announced a $1 billion investment into a new demand-side initiative to support hydrogen hubs.[233]

Based on the timeline outlined by DOE's Funding Opportunity Announcement, DOE-backed hubs will likely be selected by the end of 2023 and will begin planning, permitting, and financing in 2024. Construction is expected to begin between 2027 and 2028, with full hub scale up and operation projected in some cases by 2030.

The massive investments in hydrogen production and infrastructure support low-GHG hydrogen co-firing as a best system for certain subcategories. Hydrogen supply projections across all sectors range from 10 million metric tons (MMT) to 16 MMT for 2030 and from 20 MMT to 30 MMT for 2040.[234] With respect to the power sector specifically, Lazard (2023) estimates hydrogen supply ranging from 1.2 MMT in 2030 to 6.8 MMT in 2040.[235]

[232] CATF, *U.S. Hydrogen Hubs Map*, https://www.catf.us/us-hydrogen-hubs-map/ (last visited Aug. 3, 2023).
[233] DOE, *Biden-Harris Administration to Jumpstart Clean Hydrogen Economy with New Initiative to Provide Market Certainty And Unlock Private Investment* (July 5, 2023), https://www.energy.gov/articles/biden-harris-administration-jumpstart-clean-hydrogen-economy-new-initiative-provide-market.
[234] ERM, *Review of Projections through 2040 of U.S. Clean Hydrogen Production, Infrastructure, and Costs* 9 (2023) [Attachment 4].
[235] *Id.*

Figure 13. Clean Hydrogen Supply Projections[236]



Additionally, a recent literature review of clean hydrogen production costs put estimates between near $0 per kilogram up to around $2/k, inclusive of the 45V production tax credit.[237]

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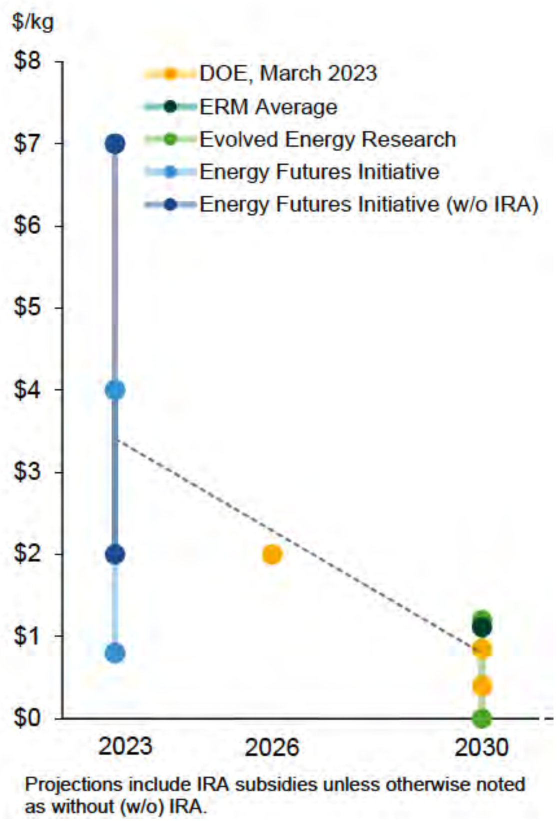
[236] *Id.*
[237] *Id.* at 5, 9.

Figure 14. Subsidized Clean Hydrogen Production Cost Projections[238]



Importantly, hydrogen co-firing can only be the "best" system of emission reduction if the type of hydrogen blended is low-GHG.[239] Since hydrogen does not generally exist in "free form" in nature, it must be produced. Hydrogen is therefore categorized into different types based on its production method. In establishing hydrogen co-firing as the best system for certain subcategories, EPA must consider the environmental impacts of blending different types of hydrogen. Combustion of high-carbon hydrogen will have the net result of *increasing* GHG pollution. Thus, for subcategories where EPA finalizes hydrogen co-firing as the best system—which Commenters support for intermediate and low loads—EPA must require that only "low-GHG hydrogen" may be blended to ensure meaningful actual reductions of overall GHG emissions. To this end, we support EPA's proposal that where hydrogen co-firing is the best system, plants must blend "low-GHG hydrogen." We support EPA's proposed definition of low-GHG hydrogen: hydrogen "produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen (kg CO_2 e/kg [hydrogen]) on a well-to-gate basis,"[240] with the caveat that EPA should not rely on the current Greenhouse Gases, Regulated Emissions, and Energy use in Transportation (GREET) model to determine

[238] *Id.* at 9.
[239] *See West Virginia*, 142 S. Ct. at 2607 (determining what system is best takes "into account cost, health, and other factors"); *Costle*, 657 F.2d at 325 (explaining Section 111 "requires EPA to weigh cost, energy, and nonair quality health and environmental factors").
[240] 88 Fed. Reg. at 33304, 33310.

emissions since the model does not yet account for indirect grid emissions associated with electrolytic hydrogen production.

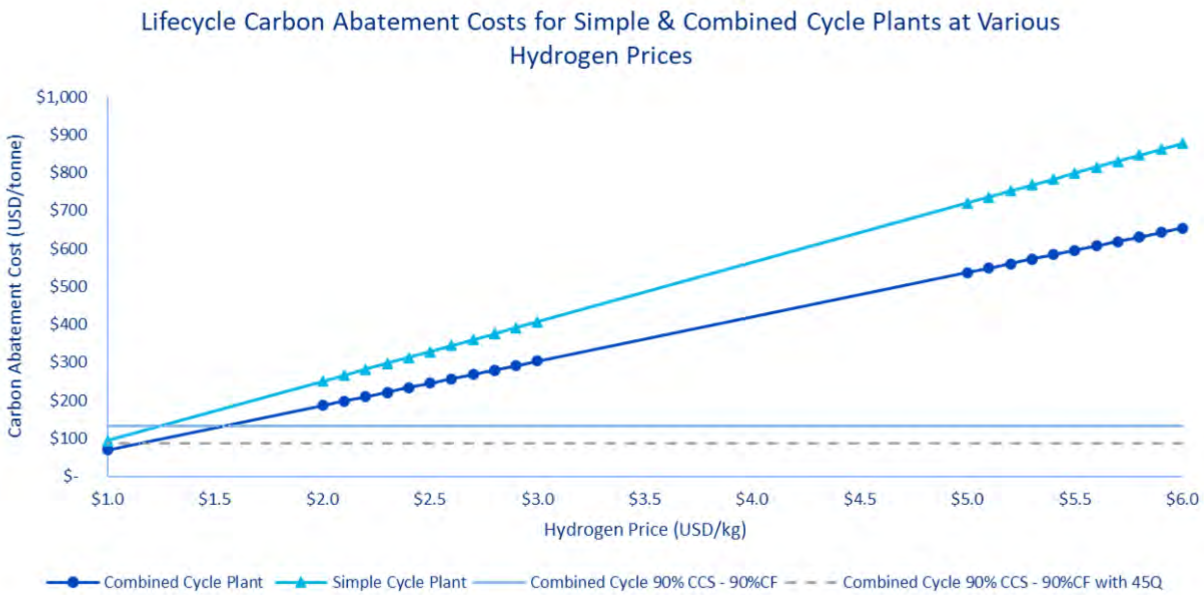
With rigorous lifecycle analysis (LCA) GHG accounting, the 0.45 kilogram of CO_2e ceiling limits co-firing to truly clean hydrogen and ensures that only hydrogen produced without creating large emissions of GHGs can qualify as the “best” system of emission reduction. In Appendix B, we describe in detail how EPA should ensure that power plants only blend low-GHG hydrogen. Specifically, EPA should only recognize hydrogen as “low-GHG hydrogen” when it demonstrates compliance with the three pillars of 1) new clean supply, 2) hourly matching, and 3) geographic deliverability. Only these criteria will ensure that electrolytic hydrogen falls under the proposed rule’s emission threshold of 0.45 kg CO_2e/kg hydrogen.

Separate from this rulemaking, Commenters urge EPA to list hydrogen production as a source category under Section 111 and set emission standards for hydrogen production facilities that use fossil fuel feedstocks. Setting standards for these sources would complement the hydrogen-based best system determination in this proposal and would ensure GHG emissions from hydrogen production are limited.

Finally, while low-GHG hydrogen will play a role in reducing GHG emissions in the regulated industry, EPA should only finalize hydrogen co-firing as the best system for intermediate and low load gas-fired EGUs. There are two reasons for this. First, hydrogen is energy intensive to produce, transport, and use, making it a higher priority to deploy where electrification is commercially or technically impossible. Low-carbon electricity is a valuable resource and should thus be prioritized toward high-value decarbonization efforts, such as displacing existing high-emission generation from the grid.

Additionally, as explained in greater detail in Appendix B, Sec. V, CCS is a more cost-efficient pollution control for baseload EGUs, while hydrogen co-firing is more cost-effective for low and intermediate gas-fired EGUs. We project total delivered costs of low-GHG hydrogen to be around \$2/kg when subsidized with Section 45V. The following graph shows a linear relationship between the carbon abatement cost (\$/ton) for co-firing hydrogen and the hydrogen price. For comparison, the graph also shows the carbon abatement costs of installing carbon capture on a representative combined cycle plant.

Figure 15. Carbon abatement costs for co-firing hydrogen in a new combined cycle plant and a new simple cycle plant[241, 242, 243]



In contrast, low-GHG hydrogen co-firing is economically preferable (and cost reasonable) for peaker and intermediate-load plants. The incremental Levelized Cost of Electricity (LCOE) and carbon abatements cost for NGCC plants with carbon capture decrease with increasing capacity factors. The incremental LCOE is derived by subtracting the LCOE for using natural gas from the LCOE for using hydrogen co-firing or carbon capture. While the incremental LCOE and carbon abatement costs for hydrogen co-firing plants also decrease with increasing capacity factors, the relationship is less pronounced; the costs of low-GHG hydrogen have a much greater influence on the incremental LCOE. CATF analysis assumes that capital, fixed, and non-fuel variable costs for hydrogen co-firing plants will be 10 percent higher than a natural gas

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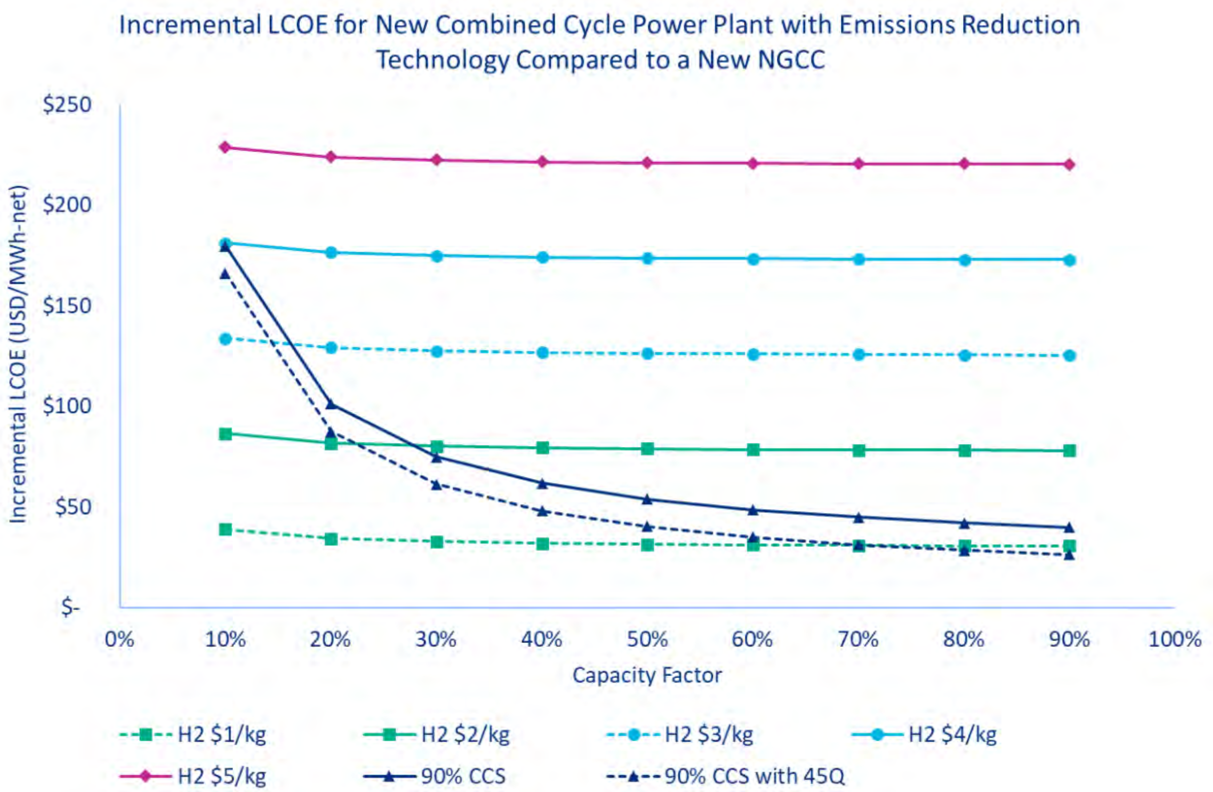
[241] CATF Analysis. Abatement costs of installing carbon capture on the same combined cycle plant are also graphed.
[242] CATF's analysis utilizes the following assumptions and sources. Plant operating data from Table 1 in EIA's *Cost and Performance Characteristics of New Generating Technologies* in the *2022 Annual Energy Outlook* and emissions data from Exhibit 5-25 in NETL's *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*. No heat rate changes between a NGCC and a hydrogen based one. Higher heat rates will increase the cost of carbon abatement for hydrogen. The 45Q credit was assumed to be fully applied at $45/ton for a 30-year amortization per EPA's *Carbon Capture and Storage for Combustion Turbines Technical Support Document,* at 11, fig.8. No additional CAPEX requirement is assumed for hydrogen operation. Adding CAPEX will increase the carbon abatement costs of co-firing hydrogen. Baseline natural gas price is $3/MMBTU-HHV. Assumed low-GHG hydrogen has a carbon intensity of 0.45 kg CO_2e/kg hydrogen, given that producers are not incentivized to go below 0.45. Upstream methane emissions is 0.99 percent with a 100-year GWP of 30. We assumed upstream CO_2 emissions amounted to 0.4 kg CO_2e/kg natural gas.
[243] Carbon abatement costs for this analysis are higher than those calculated in the previous section due to a difference in assumptions. Lower CCS carbon abatement costs will make it an even more competitive emissions reduction technology compared to co-firing hydrogen. EPA uses $3.69/MMBTU natural gas, 12 year amortization for a $85/ton tax credit, a 75 percent capacity factor, and $10/ton TS&M costs. EPA also uses a lower total as spent capital for a new combined cycle power plant with CCS that ranges from $2115 to $2329/kW. In comparison, this analysis uses EIA data that results in a total as spent capital of $3110/kW. EPA's results are also in 2018 dollars while the analysis here is done in 2024 dollars. Meeting the difference between the two will require adjusting for interest rates.

equivalent per the Electric Power Research Institute (EPRI) REGEN Model. Assuming higher costs here will increase the downward slope of the curve and shift the entire curve upwards. The higher incremental LCOE for NGCC plants with CCS at lower capacity factors means that co-firing hydrogen may be more economically viable for low-load and intermediate-load power plants. Figure 16 shows the incremental LCOE for using hydrogen co-firing and CCS across a range of capacity factors for a combined cycle plant.

Figure 16. Changes to the levelized cost of electricity (LCOE) for a combined cycle power plant with hydrogen co-firing or CCS applied for emissions reduction[244]



C. Gas Co-Firing

Gas co-firing is a cost-effective means of CO_2 emission reduction for coal-fired EGUs that operate above 20 percent capacity factor and are planning to retire in the near or medium term. EPA estimates that co-firing 40 percent gas by heat input at a representative 400 MW coal-fired unit operating 50 percent of the time reduces CO_2 emissions at a cost of $66/ton, assuming an

[244] CATF Analysis. CATF analysis assumes that capital, fixed, and non-fuel variable costs for hydrogen co-firing plants were 10 percent higher than a natural gas equivalent per EPRI, *REGEN Model*, https://us-regen-docs.epri.com/v2021a/assumptions/electricity-generation.html#new-generation-capacity (last visited Aug. 7, 2023). Actual costs may differ given that these are modeled results. Higher capital, fixed, or non-fuel variable costs will all increase the carbon abatement costs–and thus the incremental LCOE–of co-firing hydrogen. These additional costs for hydrogen co-firing plants were applied to the plant operating data obtained from Table 1 in EIA's *Cost and Performance Characteristics of New Generating Technologies* in the *2022 Annual Energy Outlook.* Plant data for NGCC plants with CCS was from the same table. For more information on the assumptions and methodology, see Appendix B.

amortization period of 6 years.[245] As a fleetwide average, taking into account the sizes and capacity factors of existing units, the similar cost-effectiveness value is $78/ton.[246] EPA acknowledges that the latter estimate is conservative because the agency did not account for co-firing equipment that is already installed or lateral gas pipelines that are already built.[247]

In addition, we note that these costs may be overestimates insofar as they assume capital costs higher than have been observed at recent projects. EPA's assumed capital cost for boiler modifications of about $52/kW derives from Sargent & Lundy's (S&L's) in-house database, with costs adjusted by an escalation factor of 2.5 percent.[248] A recent analysis by Andover Technology Partners (ATP) found similar costs for coal-fired plants that owners planned to equip to co-fire between 47 percent and 75 percent:[249] adjusted to 2021 costs using S&L's escalation factor, those plants had average capital costs of about $50/kW. Depending on the vintage of projects in S&L's database, which are not disclosed, this slightly lower value could be more representative of current capital costs to retrofit to co-fire at 40 percent by heat input. Further, S&L concludes that "fixed O&M costs and non-fuel variable O&M costs will remain roughly the same for all of the co-firing scenarios considered,"[250] while ATP estimates that lower fixed operations and maintenance costs could offset capital costs by as much as one third.[251] At any rate, ATP points out that the differential in fuel costs drive most of the abatement costs of co-firing,[252] rendering this small difference inconsequential. Thus, ATP's analysis largely supports EPA's cost-effectiveness estimates.

Regarding the delta between the cost of gas and the cost of coal, both EPA and ATP examine a differential of about $1.50/MMBTU in certain scenarios.[253]As EPA notes, however, coal-fired EGUs would likely install additional co-firing capacity so as to optimize the timing of gas combustion,[254] which could lower costs. Indeed, ATP's analysis of coal-fired plants that have deployed gas co-firing present several examples of plants that appear to have opportunistically adjusted their percentage of heat input from gas from month to month.[255] And, even at a higher gas-vs.-coal price differential of $5/MMBTU, ATP estimates cost-effectiveness (excluding gas

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[245] EPA, *Technical Support Document: GHG Mitigation Measures for Steam EGUs*, Docket ID No. EPA-HQ-OAR-2023-0072-0061, at 14-15 & tbl.1 (2023) [hereinafter *GHG Mitigation Measures for Steam EGUs TSD*].
[246] *Id.* at 15-16 & tbl.2.
[247] *Id.* at 15.
[248] Sargent & Lundy, *Natural Gas Co-Firing Memo* 15, tbl.5 & n.3 (2023).
[249] Andover Technology Partners, *Natural Gas Cofiring for Coal-Fired Utility Boilers*, at 31, tbl.3 (2022), https://www.andovertechnology.com/wp-content/uploads/2022/02/Cofiring-Report-C_21_2_CAELP_final_final.pdf [Attachment 5].
[250] Sargent & Lundy, *Natural Gas Co-Firing Memo*, *supra* note 248, at 16; *see also* EPA, *GHG Mitigation Measures for Steam EGUs TSD*, *supra* note 245, at 10.
[251] *See* Andover Technology Partners, *supra* note 249, at 40, tbl.1 (for a unit burning Powder River Basin coal, showing an annual capital payment of $2.91 million and a savings in fixed O&M of $1 million); *id.* at 42, tbl 2 (for a unit burning bituminous coal, showing an annual capital payment of $2.91 million and a savings in fixed O&M of $1 million).
[252] *Id.* at 32, 35-36 & fig.18.
[253] *Id.* at 33, fig.16; EPA, *GHG Mitigation Measures for Steam EGUs TSD*, *supra* note 245, at 16.
[254] EPA, *GHG Mitigation Measures for Steam EGUs TSD*, *supra* note 245, at 11-12.
[255] *See* Andover Technology Partners, *supra* note 249, at 19-28 & figs.5-14.

pipeline costs) below \$60/ton of CO_2 abated—well below any realistic estimate of the social cost of carbon. Therefore, co-firing gas at coal-fired EGUs is cost-reasonable.[256]

Aside from costs and abatement potential, co-firing gas at coal-fired EGUs is an adequately demonstrated system of emission reduction. EPA observes that, "during [the] 2015 through 2020 period, 29 coal-fired steam generating units co-fired natural gas at over 40 percent on an annual heat input basis."[257] Although not "routinely" utilized, this technology is plainly well demonstrated.[258] It is also evident that several coal-fired EGUs co-fired gas at high percentages of their heat input—above 70 percent—in 2020 without a full conversion to gas,[259] which supports the scenario in which owners or operators could choose to equip their units to burn more gas than is needed to meet an emission limitation in some periods and could even take advantage of extended periods of lower gas prices. Thus, while this optionality is not needed to render gas co-firing cost-reasonable, it too is well demonstrated.

Considering the energy requirements of gas co-firing at the unit, EPA notes that netting out reductions in boiler efficiency with elimination of some parasitic load associated with coal handling and emissions controls yields a change in heat rate of +/- 2 percent.[260] ATP notes that efficiency decreases for units burning Powder River Basin or lignite coal would be less significant than for units burning bituminous coal because of decreased impacts from moisture in the exhaust.[261] To the extent that coal units planning to retire in the near or medium term are more likely to be subbituminous units,[262] that fact would tend to decrease unit-level energy impacts of co-firing. At the national level, co-firing gas at coal-fired units could improve grid reliability and integration of low-cost renewables because low-load operations are easier to maintain when co-firing gas at a coal-fired EGU.[263]

Finally, EPA's estimate of the time needed to modify a boiler to co-fire gas is overly conservative. Relying on Sargent & Lundy's analysis, the agency estimates that 3 years could be needed for " conceptual studies, specifications/awards, detailed engineering, site work/mobilization, construction, and startup/testing."[264] ATP estimates a much shorter timeframe of 18 months, while noting that widespread installations could take up to 3 years due

[256] *See Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 225-26 (2009). *See also Michigan v. EPA,* 576 U.S. 743, 753 (2015) ("reasonable regulation ordinarily requires paying attention to the advantages *and* the disadvantages of agency decisions").
[257] 88 Fed. Reg. at 33352.
[258] *Cf. Essex Chem. Corp.*, 486 F.2d at 433-34.
[259] *See* Andover Technology Partners, *supra* note 249, at 12, fig.2.
[260] EPA, *GHG Mitigation Measures for Steam EGUs TSD*, *supra* note 245, at 9; *see also* Sargent & Lundy, *Natural Gas Co-Firing Memo*, *supra* note 248, at 10.
[261] *See* Andover Technology Partners, *supra* note 249, at 12, fig.2.
[262] *See* EIA, *Nearly a quarter of the operating U.S. coal-fired fleet scheduled to retire by 2029* (Nov. 7, 2022), https://www.eia.gov/todayinenergy/detail.php?id=54559 ("The type of coal used by retiring units is shifting from mostly bituminous, accounting for 68% of the U.S. coal-fired capacity that was retired from 2011 to 2020, to mostly subbituminous- and refined coal-fueled plants, which account for a combined 68% of planned retirements between 2022 and 2029. Only 31% of the planned retirements over that time period are primarily fueled by bituminous coal.").
[263] Sargent & Lundy, *Natural Gas Co-Firing Memo*, *supra* note 248, at 4-5.
[264] *See id.* at 16-17 & Fig. 1; EPA, *GHG Mitigation Measures for Steam EGUs TSD*, *supra* note 245, at 10.

to scheduling of labor and other resources.[265] Given the low number of units that are expected to fall within the subcategory for which gas co-firing is the BSER, this 3-year estimate for widespread deployment is likely conservative. In any event, coal-fired units could certainly make the boiler modifications needed to co-fire gas by a compliance deadline of 2030.

VI. Recommendations for Modifications to the Proposed Performance Standards and Emissions Guidelines

Given the costs and availability of emissions control technologies as well as the state of the power sector, Commenters offer the following recommendations to better align EPA's proposed NSPS and emissions guidelines with the Clean Air Act's goals and requirements. This section discusses Commenters' recommended modifications to the proposed performance standards and emissions guidelines for A) New Gas-Fired CTs, B) Existing Coal-Fired EGUs, and C) Existing Gas-Fired EGUs. This section concludes with an explanation of how modeling demonstrates that these recommended modifications would result in improved outcomes.

A. Performance Standards for New Gas-Fired Combustion Turbines

The "overriding purpose" of Section 111(b) is "to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is…the most effective, and in the long run, the least expensive approach."[266] It is with this Congressional intent in mind that Commenters recommend strengthening the proposed standards for the new gas turbines as set forth below.

EPA has proposed performance standards for three subcategories of new and reconstructed gas-fired CTs based on the units' annual average capacity factor.[267] EPA defines a low load (peaking) subcategory that consists of CTs with a capacity factor of less than 20 percent. The intermediate load subcategory contains those CTs with a capacity factor that ranges between 20 percent and a source-specific upper bound that is based on the design efficiency of the CT. Finally, EPA defines a baseload subcategory for CTs that operate above the upper-bound threshold for intermediate load turbines.

For the low load subcategory, EPA is proposing that the best system is the use of lower emitting fuels. For the intermediate load subcategory, EPA proposes a two phase standard: affected EGUs must meet a first phase standard of performance based on highly efficient generation by the date the rule is promulgated followed by a second phase standard based on a best system of 30 percent low-GHG hydrogen (by volume) by 2032. EGUs falling in the baseload subcategory would also have to meet a first phase efficiency standard, followed by proposed performance standards based on a best system of CCS by 2035 or co-firing of hydrogen beginning in 2032 and increasing in magnitude by 2038. Under this dual BSER, all new baseload gas EGUs would

[265] *See* Andover Technology Partners, *supra* note 249, at 17.
[266] S. Rep. No. 91-1196 (1970).
[267] The proposed regulatory text appears to require a source to have exceeded the capacity factor over a rolling 36-month average as well as a rolling 12-month average to exceed a regulatory threshold. See Table 1 of proposed subpart TTTTa. This 'both/and' approach results in overly narrow coverage; EPA should replace it with an 'either/or' approach that would include a unit in a higher-utilization subcategory if it exceeded the relevant capacity-factor threshold over any 12-month period or any 36-month period.

be required to meet a 90 lb CO_2 per MWh standard by 2035 (in the case of those facilities pursuing the former BSER pathway) or 2038 (in the case of those facilities pursuing the latter pathway).

Commenters urge EPA to modify the performance standards for new gas fired CTs in the following ways:

- Set the threshold between the low load subcategory and the intermediate load subcategory at 15 percent capacity factor or lower.
- Establish a phase two for low load subcategory units with standards equivalent to 30 percent hydrogen co-firing by 2030.
- Set a threshold between the intermediate load subcategory and the baseload subcategory at 40 percent capacity factor.
- EPA must differentiate phase-one standards for the intermediate load subcategory for NGCC units and simple cycle CTs such that simple cycle units would face an approximate 1,150 lb CO_2/MWh-gross standard while combined cycle units would face an approximate 770 lb CO_2/MWh-gross;[268] a phase-two reduction of these standards based on the co-firing of at least 30 percent hydrogen should be applied to each subcategory (CTs and CCs) within the intermediate load subcategory in 2030; a phase-three limit based on the most efficient generation technology and 96 percent co-firing with low-GHG hydrogen in 2038 would apply to the entire intermediate-load subcategory.
- For baseload new gas-fired CTs, EPA should finalize a single BSER and resulting standard based on the application of CCS by 2035.

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[268] EPA should also consider establishing this standard based on combined cycle performance alone; *see* Comments of Sierra Club submitted to the docket for this rulemaking.

Figures 17 and 18 show in table form EPA's proposed performance standards and Commenters' proposed modifications.

Figure 17. EPA's Proposed Performance Standards for New Gas-Fired EGUs

	Upon Promulgation	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low Load *<20% CF*	Use of low emitting fuels *120 - 160 lb CO2 / Mmbtu*													
Intermediate Load *20 to 40-55%CF*	Highly efficient simple cycle generation *1,150 lb CO2 / MWh-gross*					Highly efficient simple cycle generation + 30% hydrogen cofiring *1,000 lb CO2/MWh-gross*								
Baseload *>40-55% CF*	Highly efficient combined cycle generation *770 lb CO2 / MWh-gross*					*Pathway 1* Highly efficient combined cycle generation + 30% hydrogen cofiring *680 lb CO2 / MWh-gross*						Highly efficient combined cycle generation + 96% hydrogen cofiring *90 lb CO2 / MWh-gross*		
									Pathway 2 Highly efficient combined cycle generation + 90% CCS *90 lb CO2 / MWh-gross*					

Figure 18. Commenters' Proposed Modifications to Performance Standards for New Gas-Fired EGUs

		Upon Promulgation	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low Load *<15% CF*		Use of low emitting fuels *120 - 160 lb CO2 / Mmbtu*			30% hydrogen cofiring *13 percent rate reduction*										
Intermediate Load *15 - 40% CF*	*Simple Cycle Units*	Highly efficient simple cycle generation *1,150 lb CO2 / MWh-gross*			Highly efficient simple cycle generation + 30% hydrogen cofiring *1,000 lb CO2/MWh-gross*								Highly efficient simple cycle generation + 96% hydrogen cofiring *135 lb CO2/MWh-gross*		
	Combined Cycle Units	Highly efficient combined cycle generation *770 lb CO2 / MWh-gross*			Highly efficient combined cycle generation + 30% hydrogen cofiring *680 lb CO2 / MWh-gross*								Highly efficient combined cycle generation + 96% hydrogen cofiring *90 lb CO2/MWh-gross*		
Baseload *>40% CF*		Highly efficient combined cycle generation *770 lb CO2 / MWh-gross*								Highly efficient combined cycle generation + 90% CCS *90 lb CO2 / MWh-gross*					

1. It is appropriate to set subcategories based on capacity factor and Commenters' proposed adjustments to the subcategory thresholds better align with the anticipated operation of the fleet

A plant's capacity factor is an appropriate basis for subcategorization. Plants of different capacity factors are of a different "class" or "type" based solely on their differing operational profiles (i.e., how they typically ramp up or down at different times of day, or across seasons) because capacity factor influences the cost-effectiveness of pollution controls.[269]

Moreover, units of differing capacity factors differ systematically not only in their operational but also their physical characteristics. As EPA recognized in promulgating the current standards for new and reconstructed gas turbines, non-baseload units will prioritize low capital costs and the ability to start, stop and change load quickly, while efficiency is the main priority for higher-capacity-factor units.[270] Similarly, the growing segment of intermediate capacity factor CTs recognized in this proposed rule largely follows a third type of operational profile that, due to improvements in ramp rates for combined cycle units, makes determination of a separate best system for intermediate-capacity factor CTs appropriate at this time.[271]

Commenters have also proposed that the thresholds between the capacity-factor-based subcategories be modified to better reflect the future operating profiles of natural gas CTs and combined cycle units. Table 7 compares the thresholds under EPA's proposed standards and the Commenters' proposal.

Table 7. Capacity Factor Thresholds for Performance Standard for New Gas Unit Subcategories

Subcategory	EPA Proposal	Joint Commenter Proposal
Low Load Subcategory	20% or lower	15% or lower
Intermediate Load Subcategory	- CTs: Low load subcategory cutoff to 33 to 40% - CCs: Low load subcategory cutoff to 46 to 55%	CTs: Low load subcategory cutoff to 33% CCs: Low load subcategory cutoff to 40%
Baseload Subcategory	Above source-specific intermediate load threshold	Higher than 40%

These proposed revised thresholds better align with actual projected capacity factors of the different segments of the gas-fired fleet. As discussed above, under business-as-usual conditions, gas-fired power overall will see declines in utilization as more renewable energy is added to the system, displacing the need for higher marginal cost resources like gas and coal to meet demand. For example, under the NRDC Reference Case, the average capacity factor for the combined cycle fleet (both new and existing) falls to 44 percent by 2035, to 37 percent by 2040, and down

[269] *See supra* Sec. III.B.1.; 88 Fed. Reg. at 33270.
[270] *See generally* 80 Fed. Reg. at 64510 (Oct. 23, 2015).
[271] 88 Fed. Reg. at 33320 ("At the time [of the 2015 NSPS], the EPA determined that a BSER based exclusively on that more efficient technology could exclude the building of simple cycle turbines that are needed to maintain electric reliability. With improvements to the ramp rates for combined cycle units and with integrated renewable/energy storage projects becoming more common, these less efficient simple cycle turbines are no longer the only technology that can serve this purpose.").

to 31 percent by 2050.[272] Meanwhile, average capacity factors for simple cycle turbines hover around 2 percent throughout the model period.

Accordingly, setting the capacity factor threshold for true "peaking" gas-fired units, such as CTs and other low utilization units, at 15 percent more accurately reflects the very low capacity factors at which these units will operate, and in fact leaves significant headroom for more frequent operations during outlier conditions. Similarly, these business-as-usual capacity factors reflect that even those natural gas units that operate most frequently as "baseload" units will be running less frequently in the future as they move toward renewable integration and grid balancing resources. Therefore, setting the threshold for "baseload" subcategory applicability at 40 percent ensures that those units that still continue to run most frequently do so while implementing proven emission control technologies.

2. Performance Standards for Low Load Gas-Fired Units Must Be Based on the Availability and Cost Reasonableness of Co-Firing with Low-GHG Hydrogen Starting in 2030, Setting the Stage for High-Levels of Co-Firing

Commenters recommend that EPA apply a second component of BSER—co-firing 30 percent by volume low-GHG hydrogen—by 2030. It is unreasonable to base the standards for low-load new natural gas units on low-emitting non-hydrogen fuels alone. Co-firing at 30 percent low-GHG hydrogen is adequately demonstrated and cost reasonable now. While EPA expresses concern on the ability for new simple cycle turbines to co-fire higher percentages of hydrogen and whether manufacturers will focus research efforts on developing these turbines, EPA notes in the Hydrogen TSD that the "combustion turbines currently capable of co-firing greater than 30 percent hydrogen by volume are generally simple cycle turbines that utilize wet low-emission (WLE) or diffusion flame combustion."[273] Additionally, EPA cites comments from Constellation Energy explaining that "the newer simple cycle turbines can blend up to 25-30% hydrogen by volume without modification."[274] Given that simple cycle turbines are likely to be used for low-load power plants, it is our view that there is no concern about the availability of new turbines that can co-fire hydrogen at low loads.

As described at Sec. VI.D, most gas-fired units are expected to operate at increasingly low loads by the 2030s. A standard based on co-firing low-GHG hydrogen will ensure that this expanding portion of the fleet is designed and sited from the outset to control its emissions commensurate with available pollution control. While, as described below, full co-firing with low-GHG hydrogen will be available by 2030, an initial standard associated with 30 percent co-firing will allow this portion of the fleet the flexibility to perform its important role in supporting an increasingly renewable grid, while ensuring that the units are designed to ramp up co-firing volumes as supply of low-GHG hydrogen increases and performance standards are strengthened.

[272] While some new combined cycle facilities may operate at higher capacity factors, by the time the 2035 standards for baseload units apply, facilities classified as "new" under these performance standards could be as old as 10 years (as date of applicability is May 2023 and construction could take a minimum of 1.5 years). In the NRDC Reference Case, for example, two thirds of the new combined cycle capacity projected by the model is built as of 2028 and nearly all is built by 2030.
[273] *See Hydrogen TSD* at 5.
[274] *See Hydrogen TSD* at 9.

This design will also minimize leakage to less efficient and poorly controlled gas units that would occur if the low load subcategory did not have standards commensurate with the BSER - as currently proposed.

3. Initial Performance Standards for New Intermediate Load Units Must Reflect Emission Reductions

As currently proposed, EPA's performance standards for new intermediate load units are based on the emissions rate of a "highly efficient combustion turbine." During phase one of the standards, units operating in the intermediate capacity factor range would be required to operate at or below an emissions rate of 1,150 lb CO_2/MWh-gross, while phase two of the standards would require a moderate emission rate reduction to 1,000 lb CO_2/MWh-gross, in line with co-firing 30 percent hydrogen.

While a standard based on efficient CTs may be an appropriate basis for standards for intermediate load CTs in the near term, it is not an appropriate basis for standards for combined cycle units. Indeed, the average emissions rate of an existing combined cycle unit in 2022 was 871 lbs/MWh-gross, and that of units built in the last five years was 795 lbs/MWh-gross.[275] Only 5.7 percent of combined cycle generation is from facilities with an emissions rate of greater than 1,150 lb CO_2/MWh-gross and 6.6 percent of combined cycle generation is from facilities that operate at an emissions rate of greater than 1,000 lb CO_2/MWh-gross.[276] The proposed standard for intermediate load units, therefore, even accounting for reduction associated with a moderate level of hydrogen co-firing, is already well above that of the fleet average and the strong majority of operating combined cycle units, and therefore does not represent the best system.

Instead of a single standard for all intermediate load units, EPA should distinguish between simple cycle and combined cycle units in setting the BSER. These units are readily distinguished and have categorically different output-based efficiencies. Intermediate-load combined cycle units can meet standards based on combined cycle technology and EPA's standards should require this level of reduction. In the alternative, EPA should consider the use of heat recovery steam generators as part of the BSER for all intermediate-load CTs.[277]

4. EPA Should Move the Timeline for the Second Component of BSER (Co-Firing 30 Percent by Volume Low-GHG Hydrogen) from 2032 to 2030 and Apply a Third Component of BSER to the Intermediate Load Subcategory (Co-Firing 96 Percent by Volume Low-GHG Hydrogen) by 2038

Commenters support EPA's proposal to base standards for intermediate load new gas-fired EGUs on co-firing 30 percent by volume low-GHG hydrogen. As described at Sec. V.B. *supra*, 30 percent co-firing has been demonstrated and is available now. Several of the largest turbine OEMs such as GE, Siemens Energy, and MHI currently offer turbine models that can co-fire

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[275] NRDC analysis based on plant (facility) level data reported to EPA through the Continuous Emission Monitoring System and to EIA as part of Form-EIA860.
[276] Percentage figures exclude co-generation facilities and only represent combined cycle facilities that report CO_2 emissions to EPA.
[277] *See* Sierra Club comments submitted to this docket.

large amounts of hydrogen.[278] Given that the 11 engines from GE, Siemens, and MHI cited in EPA's TSD cover approximately 90 percent[279] of the market, hydrogen-ready turbines are available now. And EPA cites nearly 20 new or existing hydrogen gas turbine demonstration projects. Current hydrogen co-firing technology alongside the large number of demonstration projects make co-firing 30 to 96 percent low-GHG hydrogen adequately demonstrated. Applying the standard in 2030 will allow sufficient lead time to allow new plants to site appropriately, ensure a design that accommodates co-firing and procure sufficient supply of low-GHG hydrogen. The Clean Air Act is forward-looking and as described *supra* Sec. III.B.2, can base a standard on reasonable projections of technology at the time the standard will be applied.[280] Commenters recommend that EPA apply a third component of BSER to the intermediate load subcategory (co-firing 96 percent by volume low-GHG hydrogen) beginning in 2038.[281]

Commenters note that the intermediate load subcategory is likely to be a very small portion of the new gas fleet. In fact, in all modeled scenarios (see below for more detail), new gas units exclusively chose to operate either at low or baseload capacity factors. Therefore, while it is imperative to ensure that any unit that does choose to operate at intermediate load is controlled consistent with the best system, we anticipate that few units will operate in this subcategory. Accordingly, the amount of hydrogen infrastructure and volumes potentially needed to deploy the BSER to meet this third-phase emission limitation for this subcategory can be expected to be modest and manageable.

5. EPA Should Finalize a Standard Solely Based on CCS for New Baseload Combustion Turbines

EPA should finalize emission guidelines for new baseload CTs based on CCS for new baseload CTs, but hydrogen blending with truly low-carbon hydrogen should be an option for compliance.

If EPA were to provide two separate BSER pathways for the same set of units, with emission limits that differed in stringency by both emissions rates and compliance times, the agency would have failed to discharge its statutory duty to select the "best" system of emission reduction for the units in that subcategory. We do not understand the agency to propose this approach; rather it has described the units that adopt the hydrogen co-firing pathway and the units that adopt the CCS pathway as belonging to two separate subcategories[282] with distinct BSERs that differ depending on the characteristic of the sources in each subcategory. This approach could have been appropriate if EPA had identified objective characteristics of units that would render hydrogen co-firing more suitable and cost-effective for one set of baseload gas units, and CCS for the other set of units. EPA has not done so, however, and proposes to leave the choice of

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[278] *Hydrogen TSD* at 5-6.

[279] Envision, *Gas Turbine Manufacturers Market Share* (Oct. 10, 2018), https://www.envisioninteligence.com/blog/gas-turbine-manufacturers-market-share/ (Note: Mitsubishi Heavy Industries was known as Mitsubishi Hitachi Power Systems at the time of this article).

[280] *See NRDC v. EPA*, 655 F.2d 318, 331 (D.C. Cir. 1981); *Union Electric Co. v. EPA*, 427 U.S. 246, 256-57 (1976); *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).

[281] Note that this third component of the intermediate load subcategory is not reflected in Commenters' modeling. However, because under all modeled cases (the NRDC Reference Case, the EPA Policy Case, and Preferred Policy Case) no new CTs (whether simple cycle or combined cycle) choose to operate in this capacity factor range (15 to 40 percent) we do not expect that including this third phase would have any impact on model results.

[282] *See* 88 Fed. Reg. at 33283.

subcategory (and therefore BSER) to the owner or operator, without any criteria for evaluating that choice. This approach is not consistent with EPA's statutory responsibility to define subcategories and select the BSER for the units that fall within those subcategories.

Therefore, given the broad availability of CCS and the cost-effectiveness of deploying it at baseload gas units discussed elsewhere in these comments, EPA should eliminate the hydrogen BSER pathway for baseload gas units (both new and existing) and identify CCS as the sole BSER for those units. As explained in greater detail in Appendix B, CCS is a more cost-efficient pollution control for baseload EGUs, while hydrogen co-firing is more cost-effective for low- and intermediate gas-fired EGUs. Commenters project total delivered costs of low-GHG hydrogen to be around $2 per kilogram when subsidized with Section 45V. The relationship between carbon abatement costs and hydrogen price is linear. For combined cycle hydrogen plants, delivered costs of low-GHG hydrogen must be cheaper than $0.96 per kilogram for hydrogen co-firing to be cheaper than CCS. Thus, even with EPA's ambitious projected delivered hydrogen costs, CCS is still more economical for some base load cases.

Regarding low and intermediate loads, carbon capture on NGCC plants has incremental LCOE and carbon abatement costs that decrease with increasing capacity factors while hydrogen co-firing plants have similar incremental LCOE regardless of capacity factors. This means that at lower capacity factors, which would apply to low-load power plants and intermediate-load power plants, co-firing hydrogen may be more cost-effective than CCS.

Low-GHG hydrogen co-firing could still be used for compliance if a source demonstrated equivalency with an emission limitation reflecting 90 percent CCS in 2035. Further, existing units for which CCS is not cost-reasonable or technically feasible because of circumstances fundamentally different from those factors that EPA considered in its BSER analysis for baseload gas units could receive a less stringent standard under the RULOF provision. EPA should not, however, create a separate subcategory for baseload gas units choosing to co-fire low-GHG hydrogen when there are no identifiable characteristics that would render low-GHG hydrogen co-firing a system of emission reduction that is superior to CCS for a certain set of new or existing baseload gas units.

6. CCS Is Adequately Demonstrated and Cost Reasonable for New Baseload Gas-Fired EGUs

"Major new facilities such as electric generating plants … must be controlled to the maximum practicable degree regardless of their location."[283] As described in detail in Appendix A, post-combustion CCS is adequately demonstrated and cost reasonable for new baseload gas-fired EGUs and can effectively eliminate nearly all carbon emissions from the unit. Because CCS outperforms any other technology under the BSER factors, it must serve as the basis of performance standards for this subcategory.

Integrated CCS has been demonstrated at two commercial scale power plants and post combustion capture was successfully deployed on a gas-fired combined cycle plant for more than a decade capturing 85 to 95 percent of CO_2 from the treated gas stream. Air permits have

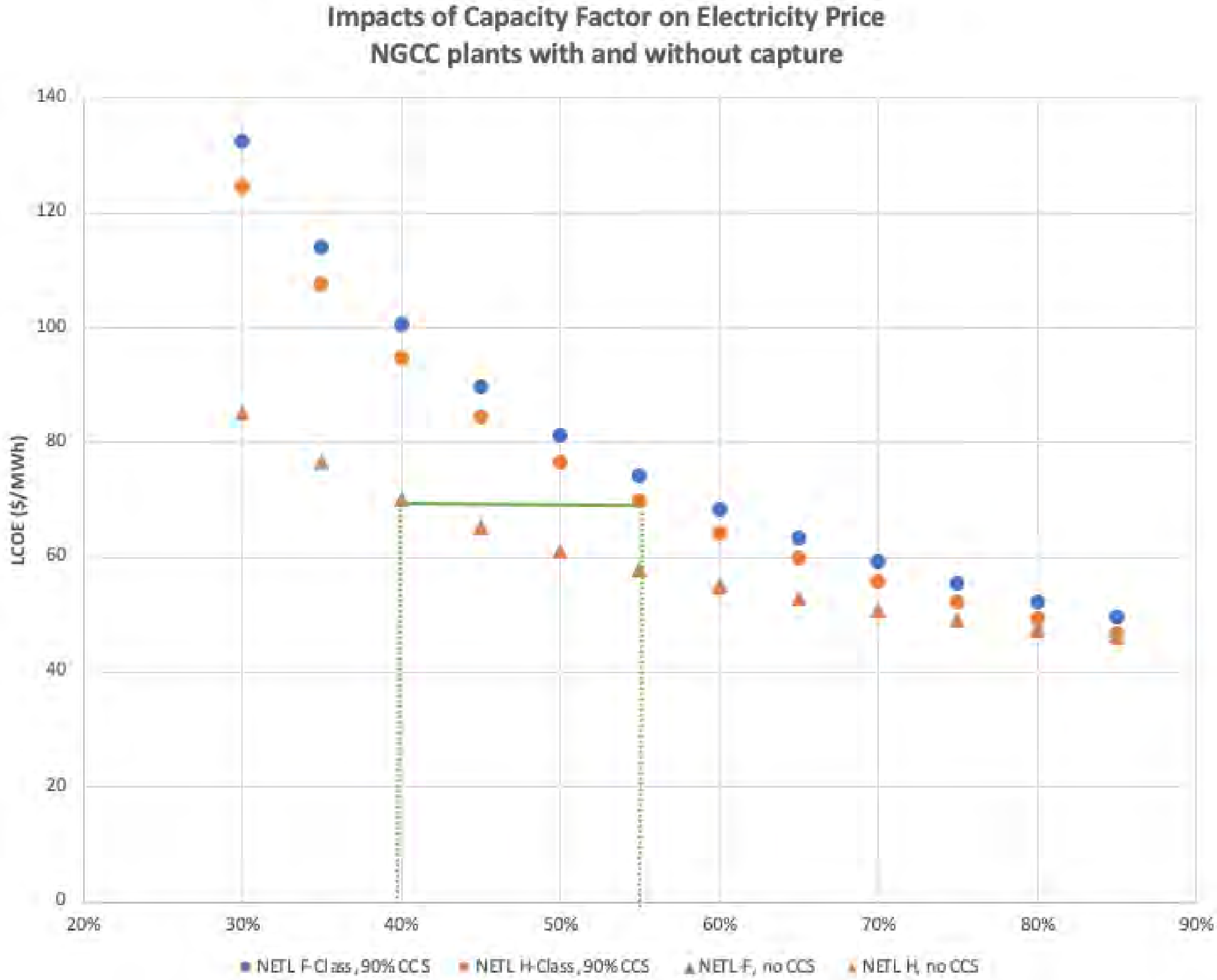
[283] S. Rep. No. 91-1196 (1970).

recently been issued to retrofit two NGCC plants with CCS and Commenters are currently tracking 17 gas-fired power plant CCS projects in the United States. The robust record described in Appendix A is more than sufficient to establish that CCS is adequately demonstrated under this forward-looking and technology-forcing section of the Clean Air Act. Moreover, while CCS is adequately demonstrated and cost reasonable for new gas plants today, EPA proposes, and Commenters support, imposing a CCS-based standard beginning in 2035 to accommodate permitting, construction, infrastructure development and other logistics not connected to the adequate demonstration of CCS.[284]

Commenters agree that the cost of an FGD wet scrubber to control SO_2 emissions is a commonsense benchmark for reasonable costs that the power sector can "adjust itself [to] in a healthy economic fashion."[285] The cost of an FGD on a representative coal-fired steam unit is $23.30 to $29.00/MWh of generation.[286] Commenters agree with EPA's analysis of the costs of CCS for new gas plants and its determination that they are reasonable. EPA determined that the incremental costs of building a new gas plant with CCS as opposed to without CCS is $3.5 to $6.4/MWh of generation or $11 to $19/ton of CO_2 reduced (depending on the turbine class). These costs compare very favorably to the FGD comparator.

[284] This approach would be consistent with past rules under Section 111 that have allowed time for full-scale deployment of the BSER and related infrastructure. *Cf.* 70 Fed. Reg. 39870, 39887 (July 11, 2005) (proposed rule; finalized at 71 Fed. Reg. 39154, 39158 (July 11, 2006)) (allowing three years to manufacture and certify fire pump engines); 56 Fed. Reg. 24468 (May 30, 1990) (proposed rule; finalized at 61 Fed. Reg. 9905, 9919 (Mar. 12, 1996)) (allowing three years for testing, control system design, and installation at new and existing landfills); 60 Fed. Reg. 10654, 10689 (Feb. 27, 1995) (proposed rule; finalized at 62 Fed. Reg. 48348, 48381 (Sept. 15, 1997)) (standard under Sections 111 and 129 providing up to five-and-a-half years for commercial waste disposal to scale up to receive wastes diverted from the regulated medical waste generators). Commenters support EPA's interpretation of Section 111 as authorizing phased-in standards of performance. *See* 88 Fed. Reg. at 33289-90. We agree that the authority to provide for lead time necessarily implies authority to implement standards in multiple phases. *See id.* We note, further, that this conclusion depends on the premise that EPA is authorized to select a multi-component BSER. This approach comports with the plain language of the statute and congressional intent to require maximum feasible emission reductions at reasonable cost. *Cf.* 80 Fed. Reg. at 64720 ("The ordinary, everyday meaning of 'system' is a set of things or parts forming a complex whole; a set of principles or procedures according to which something is done; an organized scheme or method; and a group of interacting, interrelated, or interdependent elements." (citing dictionary definitions)).
[285] *Portland Cement*, 486 F.2d at 508.
[286] 88 Fed. Reg. at 33301.

Figure 19. Impacts of Capacity Factor on Levelized Cost of Electricity; NGCC plants with and without Capture[287]



The average uncontrolled gas plant in 2035 will be operating at a capacity factor of 44 percent with no rule in place, which is why Commenters suggest setting the baseload threshold at 40 percent capacity factor. An uncontrolled gas plant operating at a 40 percent capacity factor will have a production cost of $70/MWh. Once a plant installs CCS it will have access to 45Q incentives when it captures and permanently stores CO_2 emissions. With those incentives a plant would need to run at a 55 percent capacity factor to equal the same production cost as an uncontrolled gas-fired power plant. EPA appropriately assumes that equipping the plant with CCS will lower variable costs and lead to increased dispatch. EPA concludes that a 75 percent capacity factor will be the norm for gas plants with CCS (see figure above). Commenters agree with this conclusion. For example, in Commenters' modeling of both the EPA Policy Case and the Preferred Policy Case (more detail below) new combined cycle units with CCS installed run

[287] CATF analysis using costs developed using EPA spreadsheet, "EPA-HQ-OAR-2023-0071-0057.1 (CCS Costing for combustion turbines)" with the following assumptions: CRF 12 years, natural gas price $3.69/MMBTU, $85/ton 45Q credit, 7 percent interest rate, CO_2 T&S $10/ton.

at an 85 percent capacity factor for the duration of the model time horizon. This conclusion is also supported by the literature, which indicates that "the EGU should have a significantly higher annual capacity utilization factor (due to more favorable power dispatch) with CO_2 capture and 45Q tax credits than without them. Specifically, with effective revenue coming from CCS rather than electricity sales alone, the plant is incentivized to operate continuously with less dependence on the electricity market for its profitability."[288]

7. EPA's rule should prevent a new gas unit from dropping to a lower load subcategory than its initial subcategory

Each new gas unit that elects to operate within the intermediate or baseload subcategory should not be permitted to evade emission reduction requirements by changing subcategories later on. Yet EPA's proposed NSPS for CTs appear to allow an owner or operator to shift a unit from one subcategory to another by changing the unit's capacity factor.[289] For example, a unit operating above the threshold for inclusion in the baseload subcategory could select the CCS pathway and operate unabated through 2034, dropping down to the intermediate-load subcategory in 2035, thus avoiding both the requirements for baseload units in 2035 and beyond and the requirements for intermediate units from 2032 through 2034. Or an efficient unit operating above 20 percent capacity factor could avoid requirements reflecting hydrogen co-firing by reducing utilization in 2032. In both instances, the unit would belong to a subcategory, for a time, yet never meet the emission limitation reflecting the full BSER for that subcategory—a legal impermissibility.[290] This approach would also produce an anomalous outcome: baseload units could operate with *less stringent* emission-reduction requirements than intermediate units from 2032 through 2034. And, from a policy standpoint, there would be a perverse incentive to operate units in a way that increases overall emissions from those units to avoid emission reduction requirements.

In the final rule, EPA should close this loophole and prevent new gas units from circumventing required emission reductions by dropping down to a lower-load subcategory. The agency should eliminate this loophole by classifying a unit within a subcategory based on a single 12-month period above the capacity factor threshold—a "once-in-always-in" requirement. We note that this change would be necessary even if EPA were to adopt the improvements to the NSPS for gas-fired EGUs recommended above.

B. Emission Guidelines for Existing Coal-Fired Steam EGUs

EPA has proposed emission guidelines for existing coal-fired EGUs that are divided into subcategories based on planned retirement date. For those units retiring "imminently" (before January 1, 2032—which is not "imminent" in common usage), EPA is proposing that the BSER is routine methods of operation and maintenance. Similarly, for units that are retiring in the near term (prior to January 1, 2035), and commit to operate with an annual capacity factor limit of 20 percent, EPA is proposing that the BSER is routine methods of operation and maintenance. For

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[288] Richard A. Esposito et al., *Reconsidering CCS in the US fossil-fuel fired electricity industry under section 45Q tax credits* (2019) https://onlinelibrary.wiley.com/doi/abs/10.1002/ghg.1925.
[289] *See* proposed 40 C.F.R. subpart TTTTa, tbl.1.
[290] This situation is different from the scenario in which a source retires before requirements take effect. In that scenario, the source would no longer exist and be subject to any requirements for the source category, and overall emission from the source would be lower than if the source continued to operate with less stringent requirements or even continued to operate and meet the most stringent applicable requirements.

units that are retiring prior to January 1, 2040, and that are not in other subcategories, EPA is proposing that the BSER is co-firing 40 percent natural gas on a heat input basis. Finally, EPA is proposing that the BSER for coal-fired steam EGUs that will operate in the long-term (i.e., after December 31, 2039) is the use of CCS with 90 percent capture of CO_2.

Commenters urge EPA to modify the emissions guidelines for existing coal-fired EGUs in the following ways:

- Eliminate the "imminent" retirement subcategory.
- Simplify the near- and mid-term requirements for those units ceasing operations by December 31, 2037 by establishing two capacity-factor-based subcategories:
  - For units that commit to operate with an annual capacity factor limit of 20 percent, the BSER would be routine methods of operation and maintenance; and
  - For units that do not commit to such an annual capacity factor limit, the BSER would be co-firing 40 percent natural gas on an annual heat input basis.
- Modify the long-term subcategory by moving forward the applicability date to those coal-fired steam EGUs that will operate after December 31, 2037.

Figures 20 and 21 show in table form EPA's proposed emissions guidelines and Commenters' proposed modifications.

Figure 20. EPA's Proposed Emissions Guidelines for Coal-Fired EGUs

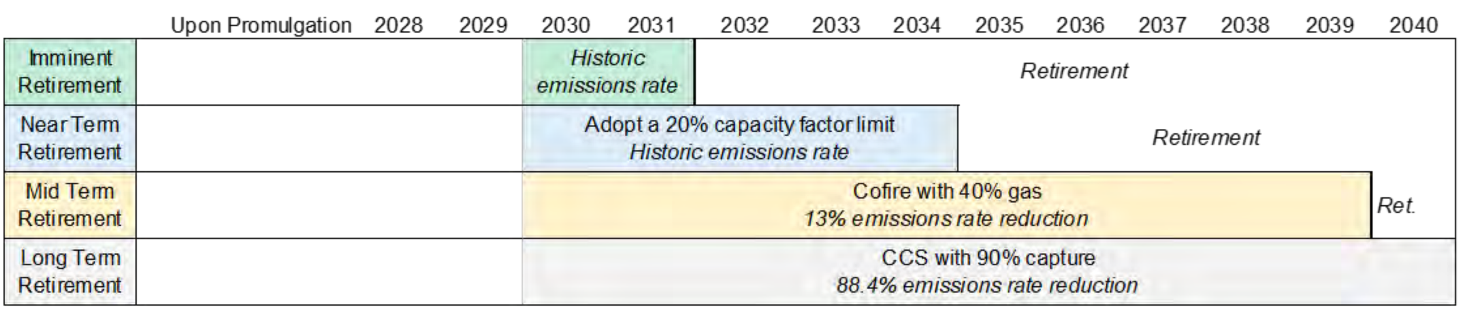
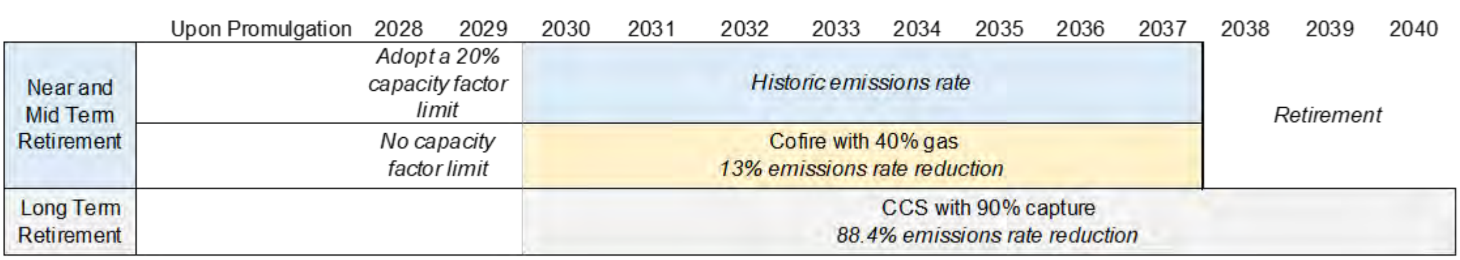


Figure 21. Joint Commenter Proposed Modifications to Emissions Guidelines for Coal-Fired EGUs



1. Establishing Subcategories Based on Operating Horizon and Capacity Factor Is Reasonable

   a. It Is Reasonable to Base Subcategories for the Coal Fleet on Operating Horizon

As discussed *infra* in Section III.B.1, EPA has the authority to distinguish between types of sources based on characteristics that are relevant to the pollution controls they can adopt. Factors such as a plant's capacity factor and its expected operating horizon are important when determining the cost-effectiveness of specific pollution control measures. A defining characteristic of the existing U.S. coal fleet is the expected pattern of retirements, even without this rule. Both EPA and industry recognize that a unit's operating time horizon determines the amortization period for the capital cost of the controls,[291] which is a crucial factor in determining the cost-effectiveness of installing carbon capture.

According to NRDC's tracking of coal facility operations,[292] as of April 2023 over 121 GW of existing coal plants, or 64 percent of 2023 coal capacity, have announced retirements through 2042. 68 GW of these plants have planned retirements by 2030, and 98 GW are planned for before 2038. In the NRDC Reference Case modeling (more details below), the rate of retirements is expected to outpace current announcements, with 127 GW (68 percent of existing capacity) of retirements by 2030, 157 GW (84 percent of existing capacity) by 2038, and all but 5 GW (97 percent) by 2045. Furthermore, in the NRDC Reference Case, coal facilities that do remain online through the coming decades are projected to run at low—and decreasing—capacity factors: the fleetwide capacity factor for coal facilities (without CCS) is projected to be 57 percent in 2025, falling to 28 percent in 2035.

   b. Commenters Recommend Simplifying the Source Categories and Emission Guidelines for Existing Coal Plants That Have a Retirement Commitment Between 2030 and 2038

As described above, EPA's proposal would establish three different subcategories for units that commit to retiring before 2040. For those units retiring imminently (before January 1, 2032), EPA is proposing that the BSER is routine methods of operation and maintenance. Similarly, for units that are retiring in the near term (prior to January 1, 2035), and commit to operate with an annual capacity factor limit of 20 percent, EPA is proposing that the BSER is routine methods of operation and maintenance. For units that are retiring prior to January 1, 2040, and that are not in other subcategories, EPA is proposing that the BSER is co-firing 40 percent natural gas on a heat input basis.

Instead, Commenters propose to streamline these three subcategories into two capacity-factor-based subcategories. Commenters also propose that these subcategories apply to those units committing to retire before 2038 (not 2040, as proposed by EPA), after which units would be subject to an emission guideline based on the application of CCS (see below). For those units retiring before 2038 and that commit to operate with an annual capacity factor limit of 20 percent, the BSER would be routine methods of operation and maintenance. For units that do not

[291] 88 Fed. Reg. at 33245.
[292] Data gathered from EIA reporting and announced retirements in utility IRPs.

commit to such an annual capacity factor limit, the BSER would be co-firing 40 percent natural gas on an annual heat input basis.

This modification achieves three outcomes. First, it improves environmental outcomes by eliminating the imminent retirement subcategory, which would allow unabated CO_2 emissions from coal facilities that are running at high capacity factors in 2030 and 2031. While capacity factors for coal facilities are dropping over time, in the near term they remain high–above 50 percent across the fleet. Allowing those facilities retiring before 2032 to continue operating, potentially at high capacity factors and with no CO_2 emissions controls or improvements, could result in millions of excess CO_2 emissions and is inconsistent with the requirements under the Clean Air Act.[293] Indeed, in our modeling of the power sector's responses to various policy design features, removing the imminent-term subcategory reduces unabated coal-fired generation in 2030 by more than half, dropping it from 187 TWh under EPA's proposal to 92 TWh under Commenters' recommended policy design. Meanwhile, moving up the retirement date to December 31, 2037 eliminates unabated coal generation in 2038, as compared to 2040 under the EPA proposal.

Second, this modification simplifies the rule and decision-making for coal facilities. Instead of facing a decision across three emissions pathways and three different retirement dates, our proposal has one retirement date (December 31, 2037) and three compliance pathways (one emission guideline for near-term retirement low capacity factor units, one for near-term retirement high capacity factor units, and one emission guideline for all other units).

Third, this modification would increase flexibility and therefore cost reasonableness of the rule. Those facilities for which a 20 percent capacity factor is cost-effective are able to pursue this option for up to eight years (from when compliance would begin in 2030), while others would have this eight-year period to recover costs of co-firing retrofits should that prove to be the most cost-effective option. As discussed in greater detail below, this flexibility allows more coal capacity to remain on the system through 2035, even as emissions are lower, compared to EPA's proposal.

2. CCS Is the BSER for Coal-Fired Steam EGUs Operating in 2038 and Beyond

As the record accompanying EPA's proposal, as well as Appendix A attached to these comments, detail, CCS is adequately demonstrated for coal-fired EGUs. Integrated CCS has been demonstrated at two commercial scale coal-fired power plants and carbon capture is currently operating on three coal-fired power plants in the United States. This demonstration is reinforced through FEED studies, permits, vendor guarantees, pilot scale projects, extensive testing and application of the technology in other industries. The limited coal fleet expected to remain in operation beyond 2038 has access to transportation and geologic storage at reasonable cost.[294]

[293] *See, e.g.*, *Am. Lung Ass'n*, 985 F.3d at 947 ("The superlative 'best' as applied to a 'system of emission reduction' plainly places a high priority on efficiently and effectively reducing emissions."), *rev'd on other grounds sub nom. West Virginia v. EPA*, 142 S. Ct. 2587.
[294] *See* Appendix A Sec. II.D.

When analyzing the cost of CCS on a coal-fired power plant, the agency properly determines that once installing CCS the power plant will operate at least at a 70 percent capacity factor as Commenters further describe in Appendix A, Sec. IV. EPA utilizes conservative transport and storage costs, *see* Appendix A, Sec. IV, yet still finds that over an 8-year amortization period, annual costs of applying CCS are \$21/MWh and \$24/ton of CO_2. This is less than the relevant comparator of the cost of installing an FGD (\$23.20 to \$29/MWh) and well below any reasonable estimate of the social cost of carbon, and therefore justifies an 8-year amortization period and a CCS-based standard for coal-fired units operating in 2038 and beyond.[295] These costs build in a retrofit difficulty factor (RDF) of 1.1 to reflect the added costs of any typical retrofit project (limited space resulting in construction premiums, insufficient laydown area, long tie-in connections).

At a ten year amortization period, the levelized cost of installing CCS is \$5/MWh and the cost-effectiveness is \$6/ton of CO_2. Because the incremental impact to the cost of generation and the cost-effectiveness with a 10-year amortization period are well below the levels that EPA has identified as acceptable elsewhere in this proposal and in other rules, EPA should reduce the amortization period assumed to be needed and identify CCS as the BSER for those units that will still be operating after 2037 but retiring before 2040.

As further described in Appendix A, Sec. VII, CATF conducted a systematic assessment of land availability surrounding the existing U.S. fleet of existing coal-fired power plants. To assume a worst case scenario, the study assumed that *no* plant had space within the existing plant boundary to site carbon capture equipment. The study assessed all coal-fired plants larger than 300MW (133 plants) and found that 98.5 percent (all but two) had access to sufficient land for carbon capture retrofit. As described above, the portion of the fleet Commenters propose to apply a CCS-based standard will only be those few plants that continue operation after December 31, 2037, therefore this conservative analysis provides sufficient evidence that covered coal-fired power plants will be able to site capture equipment.

And the attached Carbon Solutions report, discussed at Appendix A, Sec. II.D., determined that the entire coal-fired fleet remaining in operation by 2030 and operating at 30 percent capacity factor or more (136 plants) can install carbon capture and access sequestration at an average of \$86.92/tCO_2 before taking into account the \$85/ton 45Q tax credit.

Post-combustion capture and sequestration on coal-fired units exceeds every marker of adequate demonstration and reasonable costs the courts have set over the past fifty years and is the proper basis of standards for any coal-fired power plant operating beyond December 31, 2037.

3. Emission Guidelines for Existing Gas Fired EGUs

EPA has proposed emission guidelines for existing gas-fired EGUs that are based on a BSER of the application of CCS by 2035 or co-firing of hydrogen beginning in 2032 and increasing in magnitude by 2038. Under this approach, EGUs in the CCS subcategory would be required to

[295] *See Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 225-26 (2009). *See also Michigan v. EPA*, 576 U.S. 743, 753 (2015) ("reasonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions").

meet a 90 lb per MWh standard by 2035, while EGUs in the hydrogen co-fired subcategory would be required to meet the same standard by 2038. Under EPA's proposal, these emission guidelines would apply to those EGUs that have a unit capacity of 300 MW (including a proportionate share of any associated steam turbine in the case of a combined cycle gas facility) and operate at a 50 percent capacity factor or higher.

Commenters urge EPA to modify the emissions guidelines for existing gas-fired EGUs in the following ways:

- The capacity threshold for coverage by the standard should be based on capacity of the plant, not the unit. The Commenters recommend that this plant-wide threshold be set at 600 MW.
- The capacity factor threshold for coverage should be 45 percent (at the plant level).
- Similar to our proposal for baseload new natural-gas fired EGUs, EPA should finalize a single BSER for covered existing gas units based on the application of CCS by 2035.
- EPA should clarify that it is defining a subcategory of existing gas units that would be covered by this rule, leaving other units to be regulated in their own subcategories in the near future. An applicability threshold is not appropriate because the remaining units are not permanently exempt from regulation.

4. Setting a Capacity Threshold Based on Plant Capacity Rather Than Unit Capacity Will Improve Emission and Cost Outcomes

EPA requested comment on the appropriate set of covered CTs, considering how "the availability of infrastructure should inform which units should be covered in a first rulemaking."[296] EPA also stated specifically that it was considering applying the threshold for existing gas-fired CTs on a plant-level basis.[297]

Commenters agree that, in part due to the potential for shared infrastructure among co-located units, the threshold for coverage for the existing gas emission guidelines should be based on the capacity of the total plant at which a unit is located, rather than the capacity of a single unit. This approach will ensure that the standards apply to those units for which BSER is most cost effective and can have the most meaningful impact on emission without significantly increasing the number of CCS projects. A plant-based threshold means that the right set of units are covered by the rule: those where a CCS-based standard makes the most economic and logistical sense. This is in line with EPA's own explanation of how it proposed its original standard:

> The ability to cost-effectively apply CCS was a significant consideration in the EPA's selection of proposed capacity and utilization thresholds to determine which existing turbines would be covered by these proposed emission guidelines. The EPA considered two primary factors in evaluating an appropriate capacity threshold. The first is emission reduction potential. As the capacity threshold decreases a larger amount of the existing fleet is covered and overall emission

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[296] 88 Fed. Reg. at 33370.
[297] EPA, *Integrated Proposal Modeling and Updated Baseline Analysis* (Docket ID: EPA-HQ-OAR-2023-0072) (July 7, 2023).

> reduction potential increases…The second factor the EPA considered was capacity to build CCS.[298]

The cost-effectiveness of CCS at existing gas units tends to increase with the size of the facility at which they are located, as shown in the figure below and discussed further in Appendix A. There are significant economies of scale, especially regarding storage and transportation infrastructure. Covering single stand-alone units or a few larger units at a plant of multiple units inefficiently utilizes transportation infrastructure. Larger plants tend to have correspondingly larger footprints and therefore more space to install CCS infrastructure and equipment. Additionally, larger plants generally produce more CO_2 (if operated frequently), and thus can earn greater 45Q tax credits to more rapidly defray installation capital costs and fixed operations and maintenance.

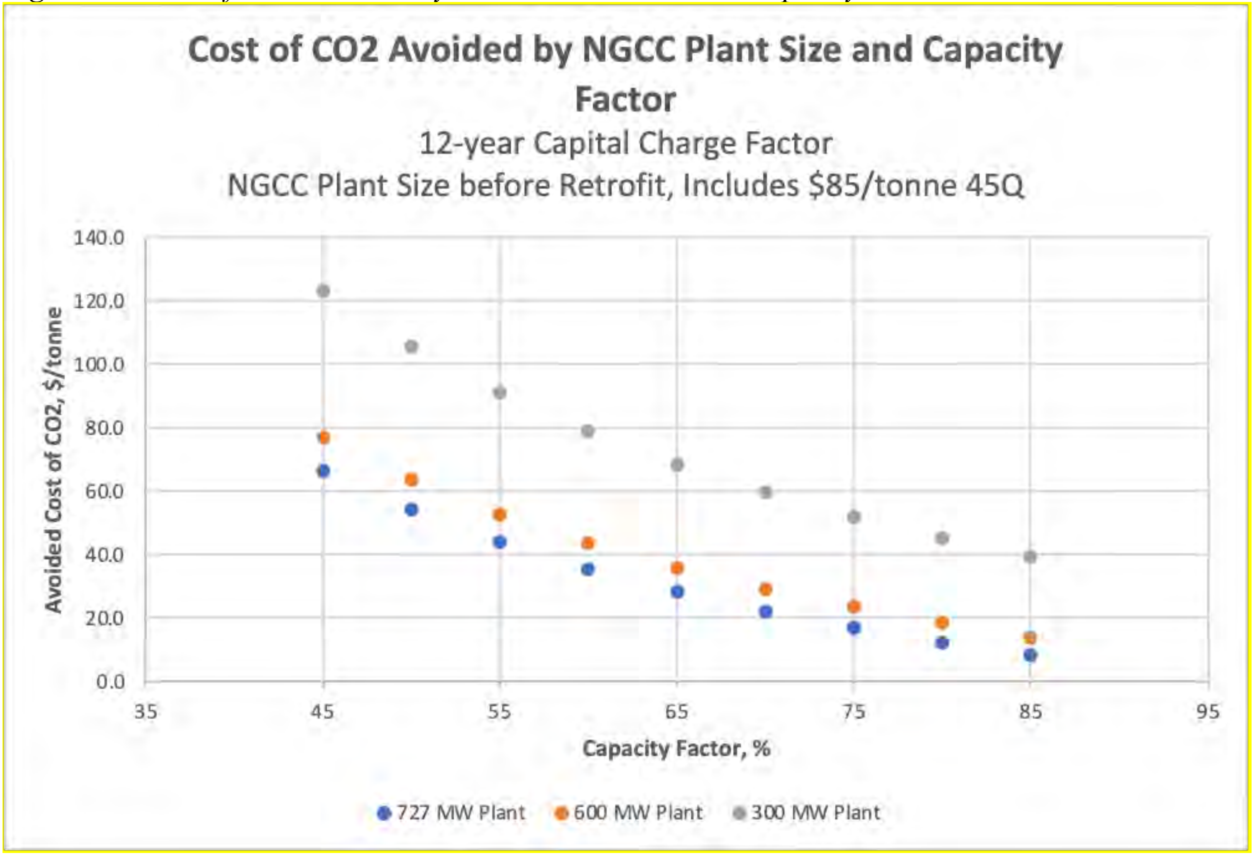
Setting the coverage threshold at the plant rather than unit level ensures that the units at the largest facilities are in fact those covered by the rule. Under EPA's proposed 300 MW unit-based standard, if the standard were applicable today, C.D. McIntosh Jr, a relatively small combined cycle unit with one 249 MW CT and one 120 MW steam turbine that operated above a 70 percent capacity factor in 2022 would be covered (since, in this example, the full capacity of the steam turbine would be allocated to the single CT unit at the facility). However, under this same standard, the 1,176 MW Deer Park Energy Center, which consists of five 180 MW CTs and one 276 MW steam turbine and operated at a 68 percent capacity factor, would not be covered. This facility is such a good candidate for CCS that it is already planning to install it in absence of the Section 111 rule and was recently issued a permit to do so.

Commenters specifically recommend that EPA set a plant-based threshold of 600 MW. This threshold reflects a facility size for which CCS is reasonable and cost-effective, and is in line with the representative existing gas-fired plant in the NETL analysis that EPA properly relies upon.[299] That representative plant consists of two 477 MWe gas turbines and a 263 MWe steam turbine—a net 727 MWe for the F-frame plant.

[298] 88 Fed Reg 33367.

[299] NETL, *Cost and Performance of Retrofitting NGCC Units for Carbon Capture (Revision 3),* at 5 (May 31, 2023), https://www.netl.doe.gov/energy-analysis/details?id=addea891-b037-4559-9f37-a2294e131ab6.

Figure 22. Cost of CO_2 Avoided by NGCC Plant Size and Capacity Factor[300]



In addition, this threshold would result in a similar number of facilities being covered by the standard as EPA had originally envisioned while increasing emissions that are covered. Based on analysis of S&P Aurora data for projected combined cycle unit operation in 2035, EPA's proposed definition of covered units for these emission guidelines (i.e., 300 MW unit, including the proportional capacity of any associated steam turbine, and a capacity factor of 50 percent or higher) would implicate 100 individual CCS projects.[301] This is 100 plants with at least one unit covered by the rule—with potential associated infrastructure, procurement, permitting, construction of CCS in order to meet an emissions standard. If EPA were to set a plant-based standard at 600 MW and change to the 45 percent capacity factor threshold we recommend, this would increase the number of projects to 130, only a 30 percent increase. At the same time, however, this would increase combined cycle emissions covered by the emission guidelines from 36 percent under EPA's proposal to 64 percent—a 78 percent increase. Figure 23 below shows

[300] CATF Analysis based on latest NETL studies and database.
[301] Using S&P Global Market Intelligence's PowerForecast model (subscription required). Market Intelligence utilizes the AuroraXMP (Aurora) tool to model a number of elements essential for the analysis of North American power markets, such as electricity prices, unit- and plant-level revenue and costs, unit- and plant-level operations, and generator supply. Aurora is a power market simulation tool based on an hourly dispatch engine that simulates the dispatch of power plants in a chronological, multi-zone, transmission-constrained system and is widely used for electric-market price forecasting, resource valuation and market risk analysis.

the capacity, plant count, and emissions coverage levels at various plant-wide capacity and capacity factor thresholds.

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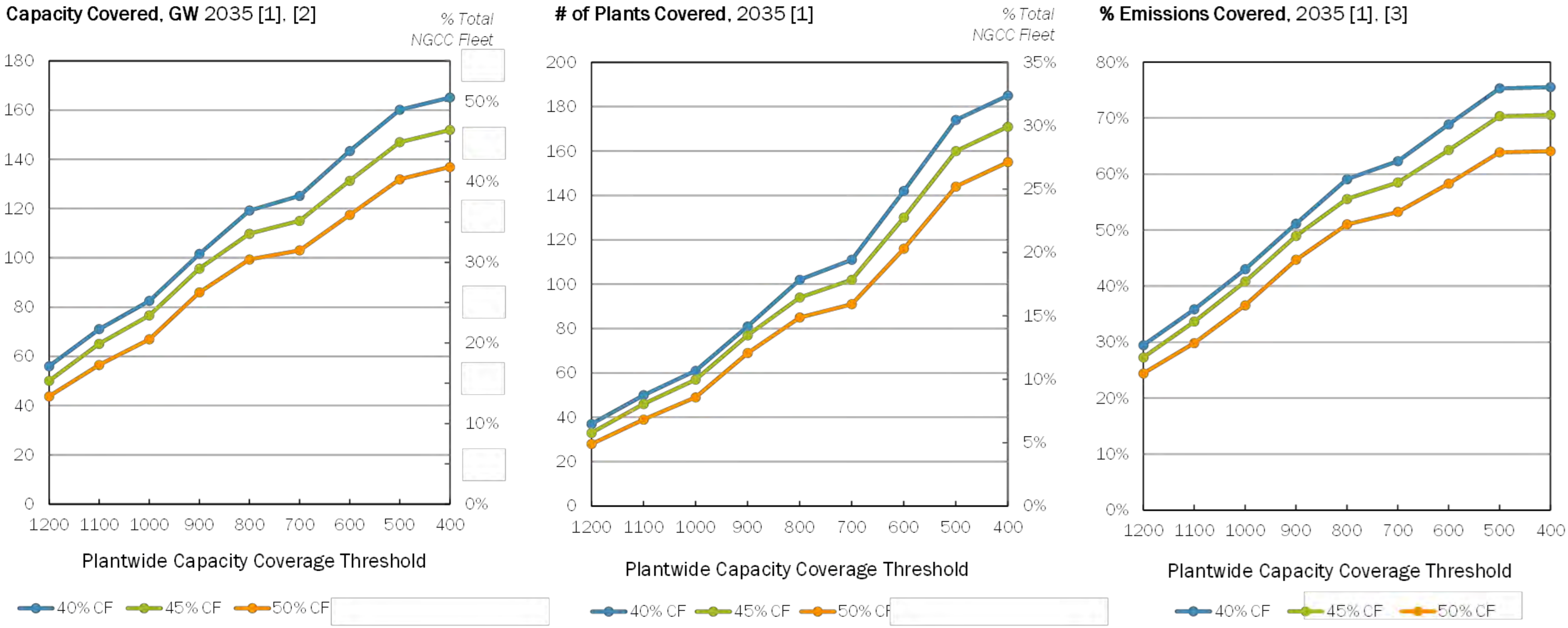
Figure 23. Capacity, Plant Count, and Emissions Coverage and Capacity and Capacity Factor Cutpoints



1. Using 2035 projected capacity factor data from S&P AURORA
2. Total GW listed here include steam turbine portions of plants that would not need to install CCS. Approximately 40% of the total NGCC fleet by capacity is steam turbines.
3. % of total projected NGCC emissions. A small portion of the fleet does not have estimated 2035 emissions; emissions for these facilities are calculated using 2022 emissions rates and projected 2035 generation

C. CCS Is the Best System of Emission Reduction for Units Located at Large, Baseload, Existing Gas Plants

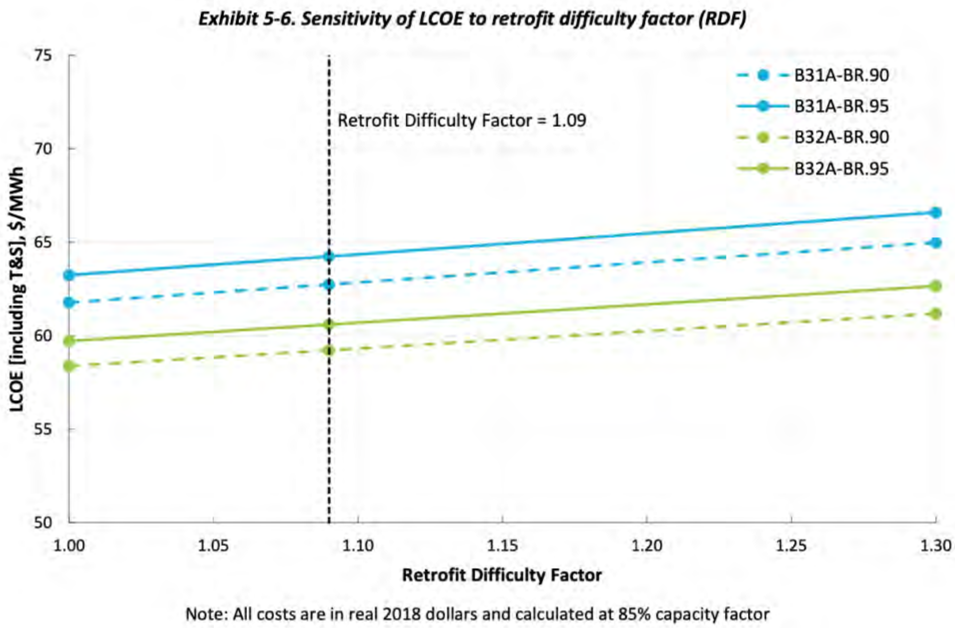
For the same reasons that post-combustion CCS is adequately demonstrated for new gas-fired EGUs, discussed above and at Appendix A, it is adequately demonstrated for existing gas-fired EGUs. The only difference is that existing gas-fired EGUs have been sited without regard to the space needed for capture equipment or access to sequestration offtake. These issues, however, do not mean that the capture technology is any different or less demonstrated.

The NETL report EPA properly utilizes to justify the reasonable costs of CCS on existing gas units accounts for the challenges of retrofitting existing gas plants compared to new ones by applying an RDF of 1.09. The RDF accounts for the cost premium for design, construction, and tie-in constraints imposed by existing plant layout and operation. NETL states that "$100 of installed greenfield equipment tends to cost $109 if installed as a retrofit." The RDF is applied to the total plant cost and applies to "generic plant locations and layouts are assumed with no space constraints."

Applying the RDF to the costs of a new gas-fired plant and using the same assumptions applied there, as discussed above, EPA determines that a 90 percent-capture retrofit of a post combustion CCS system on a gas plant increases the LCOE by $2.2/MWh. Therefore the cost of applying CCS to an existing gas plant is approximately $5.6 to $8.6/MWh. The overall CO_2 abatement cost is $18 to $26/ton depending on the class. These costs continue to compare favorably to the comparator of an FGD retrofit ($23.20 to $29/MWh).

For more complicated sites, higher RDFs may be appropriate. The NETL study conducted sensitivity analysis on the RDF. NETL found that the LCOE of existing gas retrofits were not very sensitive to the RDF over the studied range between 1.0 and 1.3. The higher RDF is meant to account for congested areas and increased difficulty associated with modifications and tie-ins to existing equipment and/or systems. Over this range, however, the change in LCOE was less than $4/MWh for both F and H class turbines. Therefore, even in the most difficult circumstances the cost of retrofitting CCS at an existing gas plant would be $12.4/MWh—almost half the cost of retrofitting a plant with an FGD.

Figure 24. Limited impact of increased difficulty on LCOE[302]



Moreover, as described in Appendix A, Sec. VII, CATF conducted a systematic assessment of land availability surrounding the existing U.S. fleet of existing natural gas plants. To assume a worst case scenario, the study assumed that *no* plant had space within the existing plant boundary to site carbon capture equipment. The study assessed all combined cycle gas plants larger than 300MW (140 plants) and found that 98 percent (all but three) had access to sufficient land for carbon capture retrofit.

And the attached Carbon Solutions report, discussed at Appendix A, Sec. II.D., determined that the entire natural gas fleet remaining in operation by2030 and operating at 30 percent capacity factor or more (429 plants) can install carbon capture and access sequestration at an average of \$86.92/ton CO_2 before taking into account the \$85/ton 45Q tax credit.

Commenters' recommendation with respect to the proposed coverage of the existing gas fleet focus on those units that are the best candidates for CCS and will likely have RDF within the range considered in the NETL study. Nonetheless, if factors not considered by the Agency render CCS retrofit exorbitantly costly, the plant owner and relevant state agency can consider those factors in setting individual standards in the state implementation plan.

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[302] NETL, *supra* note 299. These costs are amortized over 30 years, assume a capacity factor of 85 percent and do not take into account 45Q.

1. EPA Should Commit to Promulgating Emission Guidelines for the Remainder of the Existing Gas Fleet, as Is Its Legal Obligation

EPA's proposed rule fails to establish emission guidelines for the majority of emissions from the existing gas fleet—covering only 36 percent of the emissions from the NGCC fleet in 2035.[303] Although EPA clearly has the prerogative to proceed with regulating existing sources one step at a time,[304] it remains EPA's legal obligation under Section 111(d) to set emission guidelines for CO_2 emissions from the entire fleet of existing CTs. It has been nearly eight years since CO_2 standards for new CTs were established,[305] triggering the requirement for EPA to proceed under Section 111(d) to establish emission guidelines for the existing gas fleet.

It is also imperative as a matter of policy that EPA commits to a subsequent and imminent rulemaking to cover these remaining sources. At a 50 percent capacity factor cutoff, a significant number of gas plants may choose to curtail their operations to continue running without CO_2 controls. Our modeling has found that under EPA's proposed rule, 82 percent of existing NGCC capacity opts to operate below 50 percent capacity factor in 2038, compared to 64 percent of the existing NGCC fleet under the NRDC Reference Case. To avoid this leakage to the uncontrolled subcategory, EPA must timely determine the BSER, set an emission limit and establish emission guidelines for the remaining gas fleet in a subsequent rulemaking.

D. Modeling of Proposed Modifications Shows Improved Outcomes at Minimal Cost

In order to explore the economic and environmental impacts of the modifications to the proposed standards described above, Commenters conducted modeling utilizing the IPM. Specifically, the Commenters explored three main scenarios:

- NRDC Reference: a reference case for future electric system operations without any incremental 111 standards. As described in more detail below, this reference case differs in small ways from EPA's reference case in both its assumptions and projected outcomes;
- EPA Policy Case: a case imposing EPA's proposed standards for existing coal units, existing gas units, and new gas units; and
- Preferred Policy Case: a case imposing EPA's proposed standards as modified per the recommendations described above.[306]

Commenters also ran a High Demand sensitivity on both the NRDC Reference case and the Preferred Policy Case to assess the impact of the rules under a scenario that reflects stronger electric demand associated with increased electrification.

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[303] This is based on projections of unit-level capacity factors for NGCC plants in 2035 from S&P's Global Market Intelligence PowerForecast. Subscription required for S&P forecast data. This is the percentage of emissions covered in the absence of the rule (i.e., not accounting for any dispatch shifts that may occur as a result of the rule).
[304] *Massachusetts v. EPA*, 549 U.S. 497, 524 (2007) ("Agencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop.").
[305] 80 Fed. Reg. 64509 (Oct. 23, 2015).
[306] *See supra* note 281, noting that this modeling does *not* include a final phase of emissions standards for intermediate load new gas-fired units, but that we would expect this to have no effect on model results.

The Preferred Policy Case results in an additional reduction of 397 million short tons of CO_2 compared to EPA's Policy Case between 2025 and 2042,[307] or an additional 3.2 percent reduction in emissions. System costs are minimally lower, with cumulative costs over the same time period decreasing by 0.9 percent. Compared to the NRDC Reference Case, the Preferred Policy Case would reduce CO_2 emissions by 2.3 billion short tons between 2025 and 2042 (a 16.4 percent reduction), reduce NO_x emissions by 599 thousand short tons between 2025 and 2042 (a 10.4 percent reduction), and marginally reduce costs (by 1.1 percent). Under the High Demand sensitivity, as compared to the NRDC Reference Case (High Demand) the Preferred Policy Case (High Demand) would reduce CO_2 emissions by 3.06 billion short tons between 2025 and 2042 (a 20.0 percent reduction), reduce NO_x emissions by 684 thousand short tons between 2025 and 2042 (an 11.3 percent reduction), and marginally decrease costs (by 0.77 percent).

The section below explores the key findings from these policy runs in more detail.

1. The NRDC Reference Case

NRDC has utilized IPM to assess the impact of environmental standards in the power sector for more than a decade. The foundation of our analysis of EPA's proposed Section 111 standards was NRDC's Reference case, finalized in June of 2023 and reflecting a baseline case that accounts for finalized federal, state, and regional energy policies as of April of 2023, including the IRA. The Commenters formulated our analysis based on electricity demand and fuel price assumptions taken from the EIA's 2023 AEO, with technology costs taken from multiple sources including EPA v6 Post-IRA 2022, NREL's ATB 2022, and AEO 2023. See Appendix C for additional details on the assumptions for these scenarios. While this NRDC Reference case is in many ways similar to EPA's Reference Case, it differs in a handful of important ways:

- Updated demand, cost, and performance values: EPA relies on AEO 2021 (demand, macroeconomic, and conventional technologies) and NREL's ATB 2021 (renewable and storage prices). NRDC has updated its assumptions to reflect the most recent versions (as of April 2023): AEO 2023 and ATB 2022.
- Updated state policy: NRDC reflects state policy as of April 2023 (EPA is as of fall 2022) with more granular representation of some statewide clean energy policies.
- Updated announced firm builds and retirements: NRDC reflects announced retirements, including those announced in some utility IRPs and firm builds (those in advanced development or under construction) as of April 2023. EPA's list is as of October 2022 and does not include all coal retirements set in IRPs.
- Longer-duration storage: NRDC includes 10-hour storage, in addition to the 4- and 8-hour storage options EPA also includes. Costs are drawn from NREL ATB 2022.
- Higher hydrogen prices: NRDC has a subsidized cost of hydrogen in 2023 of \$3/kg, declining to \$2/kg by 2035.
- Endogenous operation and retirement of nuclear: EPA's most recent baseline does not allow for the endogenous retirement of nuclear. The NRDC Reference Case version

[307] Year ranges in text reflect calendar years associated with IPM model run years; years shown in figures reflect IPM model run years. Mapping of calendar years to run years in IPM-NRDC are detailed in Appendix C.

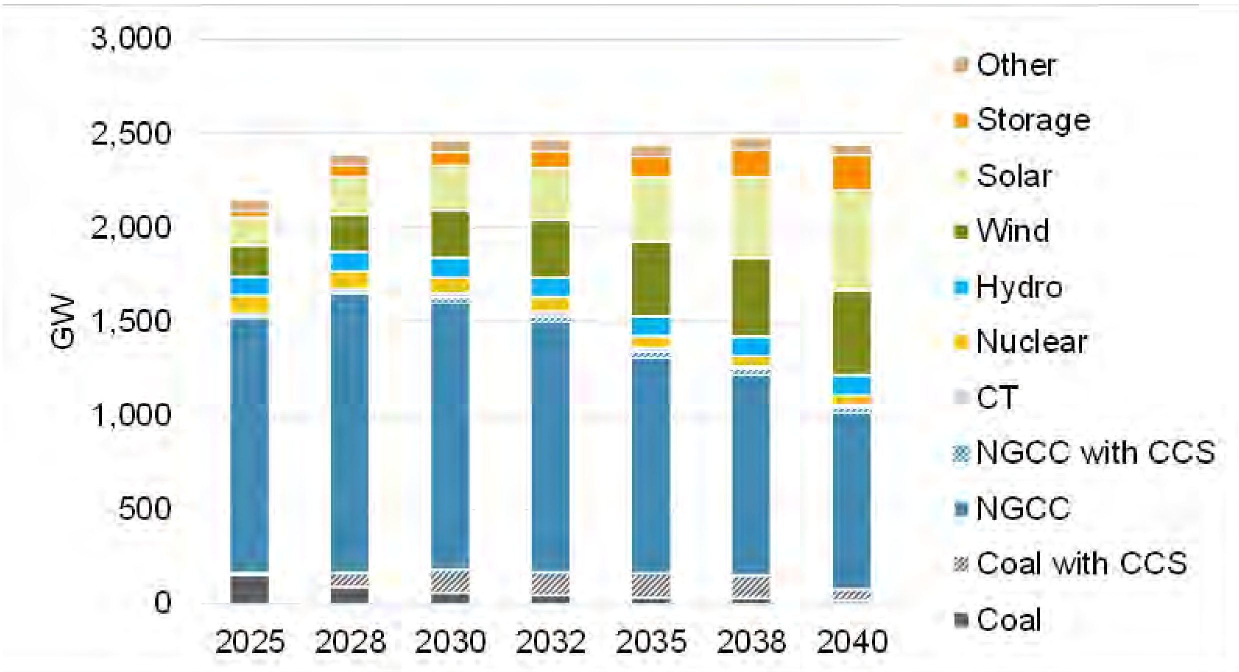
allows the model to retire and operate plants based on least-cost optimization with some constraints based on regulatory status.
- Different treatment of the capacity value (or ELCC, the effective load carrying capability) of renewables and storage: EPA uses a "declining reserve margin" approach for both renewables and storage additions, where the capacity value (for meeting capacity margins) declines significantly as more capacity is added to the grid. NRDC does not take this approach and instead uses the model's default static values and gives 10-hour storage full accreditation.

While overall the models produce similar results, these differences in vintage of sources and treatment of certain plant types result in NRDC's analysis generally seeing greater retirement of nuclear, less investment in and reduced operation of gas, and a greater deployment of renewables and storage (though, as discussed above Sec. IV.D, the levels of renewable deployment in both EPA-IPM and NRDC-IPM remain well below other models' deployment levels).

Under the NRDC Reference case, electricity sector CO_2 emissions are projected to continue a steadily declining trajectory, reaching 876 million short tons in 2030 and 443 million short tons in 2040, equivalent to a 67 percent and 83 percent reduction below 2005 levels, respectively.

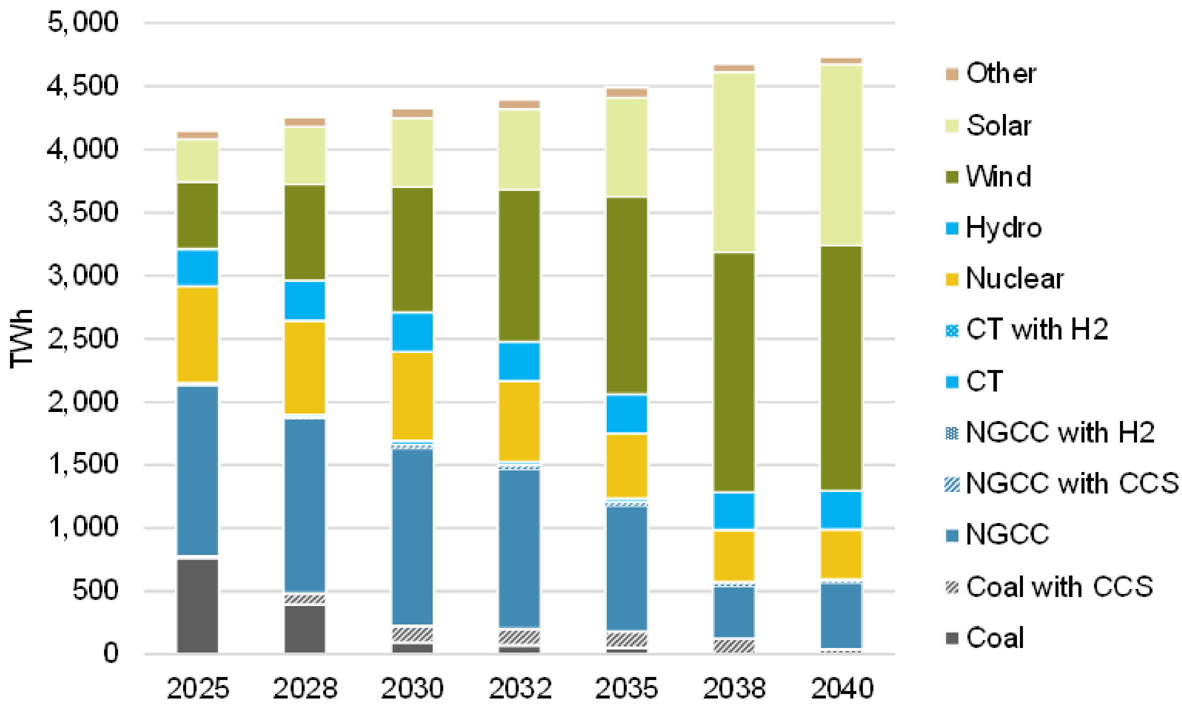
These reductions are driven by numerous market dynamics that result in the continued rapid growth of renewable generation resources and moderate increases in natural gas capacity. For renewables, this growth is spurred by low and further declining costs of renewable projects along with improving renewable technology, declining costs of technologies like battery storage that enable additional renewable capacity on the electricity grid, federal tax incentives as expanded and extended by the IRA, and state policies supporting investment in clean energy resources. The model also projects some limited economic deployment of CCS, mostly on coal resources, under the NRDC Reference case, as the expanded 45Q tax credit creates favorable economic conditions for this technology. *See* Figure 25.

Figure 25. NRDC Reference Case Electric System Capacity (GW)



Generation from fossil resources uncontrolled for CO_2 is projected to significantly reduce over time under the NRDC Reference Case (see Figure 26). Over 100 GW of coal capacity is projected to retire between 2025 and 2034, due largely to competitive gas prices and increased renewable development as well as existing federal and state regulations. In 2038, 31 GW of coal capacity remain online in the reference case. Natural gas generation also significantly decreases, mostly due to reduced run rates (capacity factors) across the fleet: existing NGCC units run at an average capacity factor of 56 percent in 2025, falling to 48 percent in 2032 and 33 percent in 2040. Fleetwide (including new facilities), NGCC capacity factors are 51 percent in 2032 and 37 percent in 2040.

Figure 26. NRDC Reference Case Electric System Generation (TWh)



2. Detailed Findings

Our modeling of both the EPA Policy Case and Preferred Policy Case shows meaningful emission reductions as compared to the Reference Case. The Preferred Policy Case would reduce cumulative CO_2 emissions by 2.34 billion short tons between 2025 and 2042 (a 16.4 percent reduction), while the EPA Policy case would reduce cumulative CO_2 emissions by 1.9 billion short tons (a 13.6 percent reduction) over that same period (see Figure 27). Both policy cases would also reduce NO_x emissions; the Preferred Policy Case by 10.4 percent between 2025 and 2042 and the EPA Policy Case by 8.7 percent over the same period.

Figure 27. Cumulative Avoided CO_2 Emissions (compared to NRDC Reference Case), million short tons

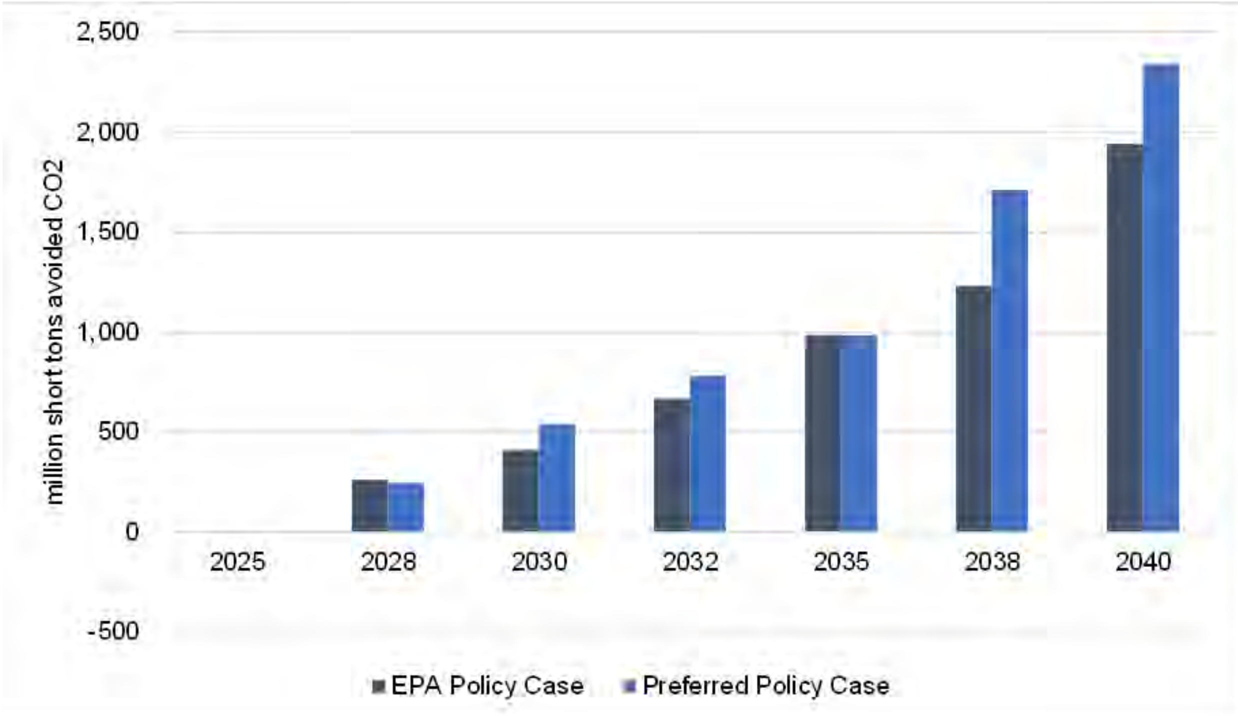
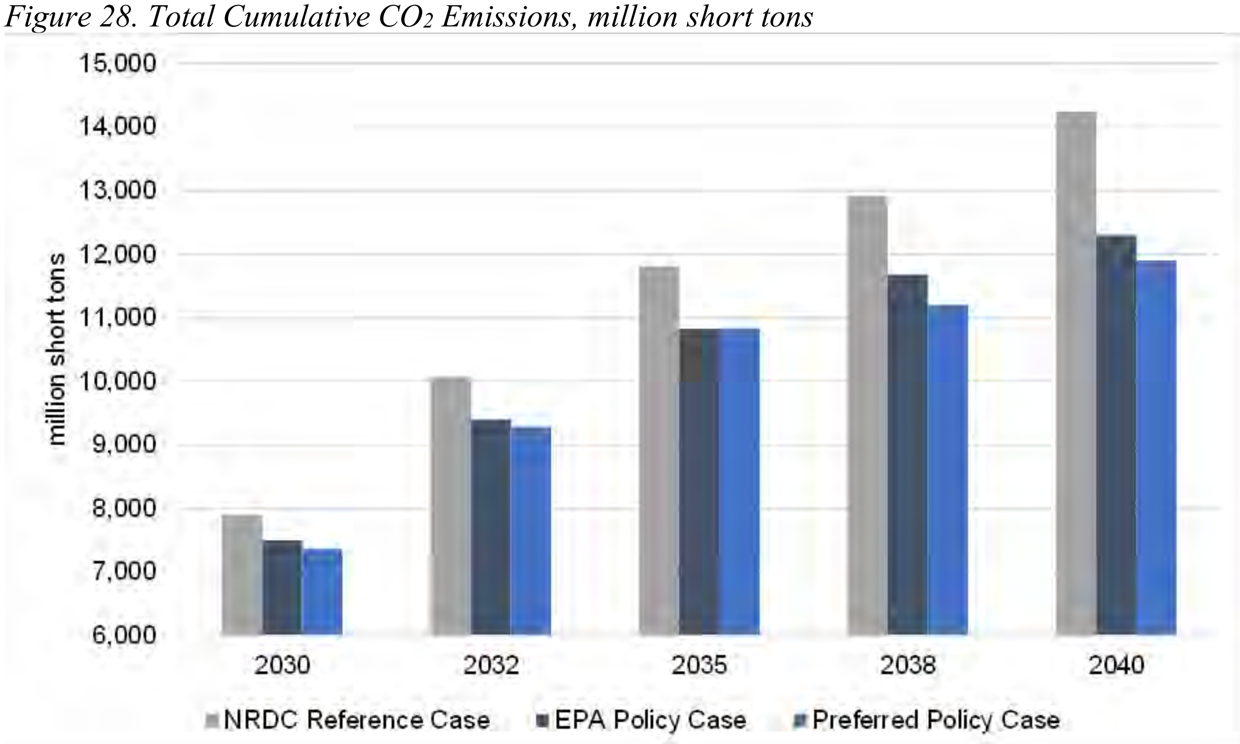


Figure 28. Total Cumulative CO_2 Emissions, million short tons



Under the NRDC Reference Case, coal generation decreases significantly across the model period, from 774 TWh in 2025, to 372 TWh in 2030, and 100 TWh in 2040. Over this time, coal capacity factors drop as well (i.e., the rate of reduction in generation outpaces the rate of reduction in capacity), from 57 percent in 2025 to 47 percent in 2030 and 25 percent in 2040. This generation trend is accelerated under both the EPA Policy Case and the Preferred Policy Case: unabated coal generation drops to zero in 2040 under the EPA Policy Case and 2038 in the Preferred Policy Case. Capacity factors remain largely similar under the EPA Policy Case but drop more quickly under the Preferred Policy Case, to between 15 and 20 percent from 2030 and onwards. This final trend is a function of the Preferred Policy Case's increased flexibility for coal units, allowing more coal units to remain online until 2038 but operating at lower capacity factors, even as system-wide emissions decrease.

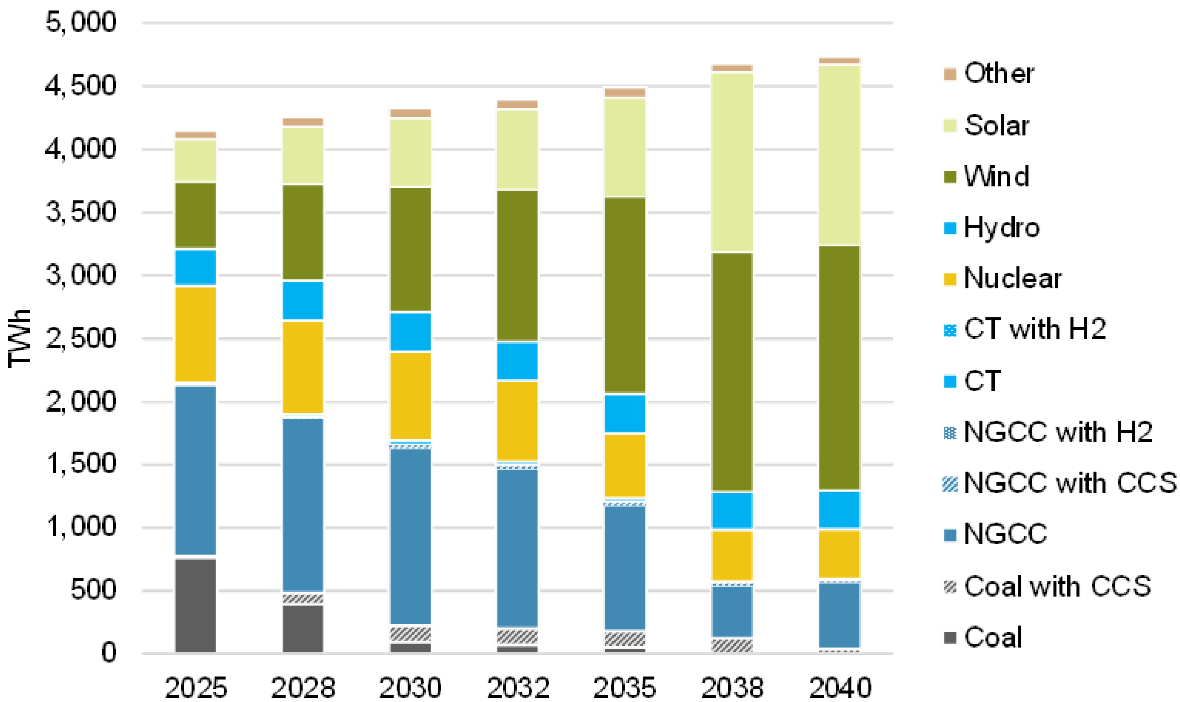
Under both the EPA Policy Case and the Preferred Policy Case, the modeling shows a slight increase in deployment of CCS on coal units and an acceleration of uncontrolled coal unit retirement. While the NRDC Reference Case projects 62 GW of coal retirements between 2028 and 2039, the EPA Policy Case shows 80 GW of retirements and the Preferred Policy Case 95 GW. By 2035, the NRDC Reference Case projects 18.4 GW of coal with CCS, compared to 21.4 GW under the EPA Policy Case, and 18.5 GW under the Preferred Policy Case.

Meanwhile, unmitigated natural gas generation reduces from a third of total generation in 2025 to 21 percent in 2038 under EPA's Policy Case and 9 percent under the Preferred Policy Case. This occurs due to lower additions of new units (especially combined cycle units) as well as an acceleration of the trend of existing natural gas fired units to operate at lower capacity factors for reliability and intermittent resource integration. Under the NRDC Reference Case, 60 percent of existing NGCC units are projected to operate at a capacity factor below 50 percent in 2035, rising to 64 percent of the fleet in 2038. Under the Preferred Policy Case, 79 percent of the fleet is projected to operate under 50 percent capacity factor in 2032, 82 percent by 2035, and nearly all (95 percent) by 2038. In all cases, including the Reference Case, in 2038 a strong majority of these units are operating below 40 percent capacity factor.

All cases see similar deployment of CCS on NGCC units—between 3 and 4 GW by 2035. The NRDC Reference Case and EPA Policy Case see no co-firing of hydrogen at natural gas-fired units. There is limited hydrogen co-firing seen at new CTs beginning in 2030 in the Preferred Policy Case due to the inclusion of stronger standards on new peaking gas units—around 400 to 1,500 GWh annually, or between 3 to 15 percent of all CT generation.

Similarly, under both the EPA Policy Case and the Preferred Policy Case, the modeling shows an acceleration of renewable deployment and a corresponding reduction in generation from natural gas units. Under the NRDC Reference Case, wind and solar generation increases from 33 percent of total generation in 2030 to 54 percent by 2038; under the EPA Policy Case and Preferred Policy Case, wind and solar generation are 57 and 71 percent of total generation in 2030 and 2038, respectively.

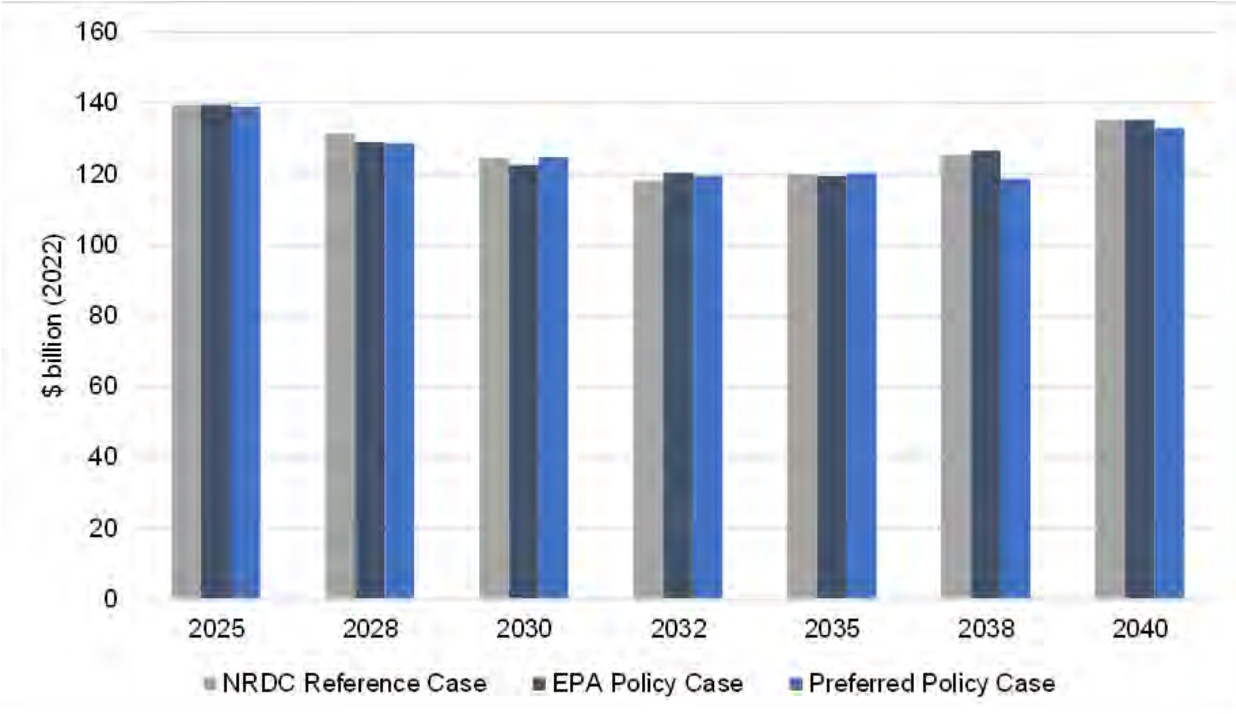
Figure 29. Preferred Policy Case Electric System Generation (TWh)



As previously discussed, these generation trends seen in the modeling of the Policy Cases are continuations and in some cases accelerations of existing economic trends expected across the electric sector in the coming decades. Accordingly, the impact on total system costs of achieving these important incremental emissions reductions is minimal and indeed, through the years of focus reflect a reduction in costs compared to the NRDC Reference Case.[308] As shown in Figure 28, total system costs from 2025 through 2042 are extremely similar across all three analyzed cases. Cumulatively over this period, total system costs of the Preferred Policy Case are 1.05 percent below the NRDC Reference Case.

[308] System costs reported by IPM consist of fixed and variable operations and maintenance, fuel costs, capital costs, and CCS costs, all net of tax incentives. IPM is a cost optimization model that minimizes costs over the full model period, which for this analysis was 2025 through 2054. Over the full model period, total system costs were slightly higher under the Preferred Policy Case as compared to the NRDC Reference Case.

Figure 30. Total Annual System Costs, billion $2022

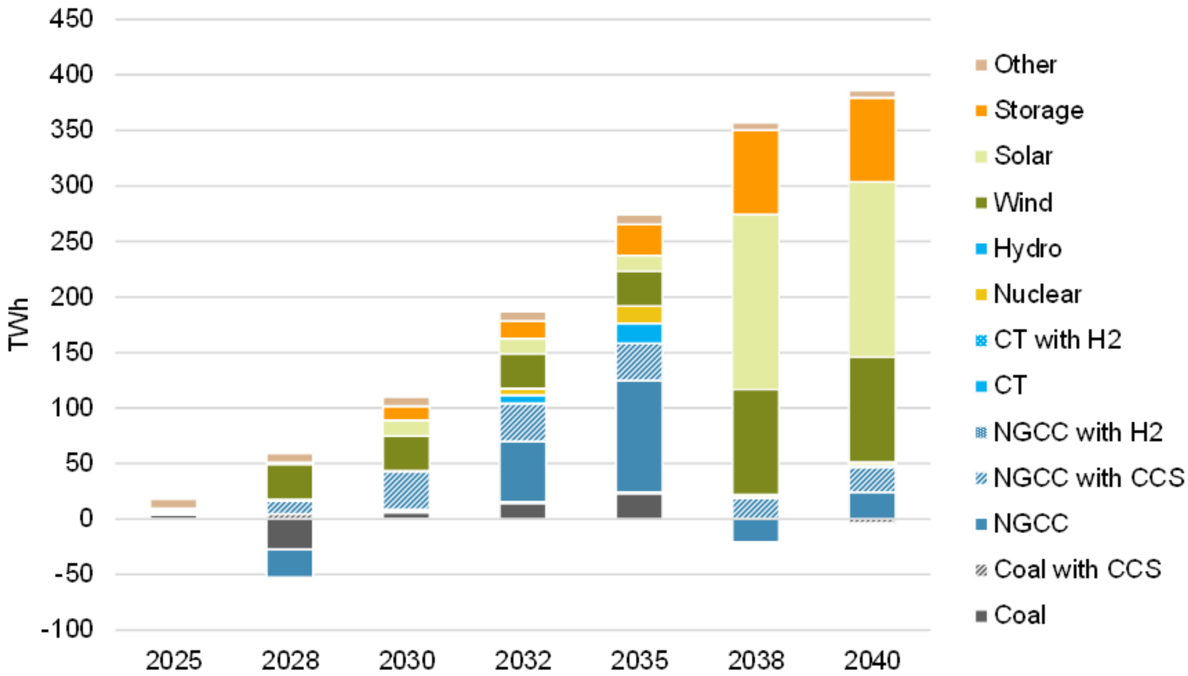


Modeling of the High Demand sensitivities of the NRDC Reference Case and Preferred Policy Case shows that the Preferred Policy Case remains a robust policy design even in the case of higher electricity demand. This sensitivity increased total electric demand across the model period in line with projected increased energy demand due to advanced electrification beyond what is already projected in AEO 2023.[309] This results in a 10 percent increase in demand by 2035 and a 22 percent increase by 2050 compared to the baseline NRDC Reference Case and Preferred Policy Case.

Under the High Demand sensitivity, as compared to the NRDC Reference Case (High Demand) the Preferred Policy Case (High Demand) would reduce CO_2 emissions by 3.06 billion short tons between 2025 and 2042 (a 20.0 percent reduction), reduce NO_x emissions by 684 thousand short tons between 2025 and 2042 (an 11.3 percent reduction), and marginally decrease costs (by 0.77 percent). Renewable and storage capacity deployed and generation increases slightly in order to meet incremental demand under the Preferred Policy Case (High Demand), as does combined cycle generation, both with and without CCS. See Figure 31.

[309] *See* Appendix C for more detail.

Figure 31. Difference in Generation, Preferred Policy Case (High Demand) compared to Preferred Policy Case (TWh)



VII. EPA Reasonably Relies on its Expertise and Past Experience in Accurately Projecting the Pace and Scale of Technology Development

The standards proposed here are not the first time EPA has established performance standards based on systems that may require build-out of pollution control equipment and related infrastructure. Indeed, as discussed *supra* at Section III.B.2, EPA is authorized under Section 111 and other provisions of the Clean Air Act to set standards that anticipate improvements in emissions performance and provide adequate lead time for meeting emission reduction targets. This is a clear and core part of Congress's statutory design. While this proposal does not advance such an outcome, the Clean Air Act's technology-forcing provisions are "expressly designed to force regulated sources to develop pollution control devices that might at the time appear to be economically or technologically infeasible."[310] Congress understood that protecting public health "may mean that people and industries will be asked to do what seems impossible at the present time."[311] Importantly, the requirement under Section 111 that a technology be "adequately demonstrated" does not require the technology already be "routinely achieved within the industry prior to its adoption," rather, it must simply be "reasonably reliable, reasonably efficient," and not "exorbitantly costly in an economic or environmental way."[312]

As such, Congress assigned EPA the task of determining the BSER and emission limitations based on it pursuant to the forward-looking and technology-forcing directive while also providing adequate lead time to meet emission standards. Using its long experience and special

[310] *Union Elec. Co. v. E.P.A.*, 427 U.S. 246, 257 (1976).
[311] *Id.* at 258-9 (quoting Remarks of Sen. Muskie, 116 Cong. Rec. 32901-32902 (1970)).
[312] *Essex Chem. Corp.*, 486 F.2d at 433-34.

expertise from five decades of prior work setting similar rules for the power sector and other industries, EPA has reasonably examined the time needed to install control technologies as well as the time needed to scale up necessary infrastructure such as transmission lines, pipelines, and waste disposal.[313] Recognizing that "building the infrastructure required to support wider use of CCS and qualified low-GHG hydrogen in the power sector will take place on a multi-year time scale,"[314] EPA has reasonably accounted for those needs in its compliance timelines. Regulated industries have risen to the occasion time and time again to rapidly develop and deploy necessary technologies and infrastructure when called upon. There is clear evidence that the prospect of pollution regulations has accelerated the pace at which industries innovate.[315] Prior power sector regulations provide ample evidence of both EPA's special expertise in assessing adequate lead time and the power sector's ability to rapidly scale up technologies and infrastructure. The following three sections provide illustrative case studies representing both EPA's expertise in projecting lead time and the power sector's ability to rapidly scale up operations and install control technologies.

A. Infrastructure Deployment Anticipated Under Proposed Standards

EPA's proposal allows ample time for installation of any control equipment needed to comply, and is in line with prior regulations for the power sector. Under EPA's proposal, emission limits that will require some control equipment installation or increased use of less-polluting fuels apply only to subcategories of existing units that will operate above specified capacity factors or for many more years. Existing units that operate at or below the specified levels need only maintain the emission rates produced by their current controls or are not subject to standards in the current proposal.

The majority of the existing coal fleet is retiring before 2038 and will not be subject to CCS-based standards. And as described above, most gas-fired power plants are expected to operate at lower capacity factors in the mid-2030s and thus also will not be subject to CCS- or hydrogen-

[313] This approach would be consistent with past rules under Section 111 that have allowed time for full-scale deployment of the BSER and related infrastructure. *Cf.* 70 Fed. Reg. 39,870, 39,887 (July 11, 2005) (proposed rule; finalized at 71 Fed. Reg. 39154, 39158 (July 11, 2006)) (allowing three years to manufacture and certify fire pump engines); 56 Fed. Reg. 24468 (May 30, 1990) (proposed rule; finalized at 61 Fed. Reg. 9905, 9919 (Mar. 12, 1996)) (allowing three years for testing, control system design, and installation at new and existing landfills); 60 Fed. Reg. 10654, 10689 (Feb. 27, 1995) (proposed rule; finalized at 62 Fed. Reg. 48,348, 48,381 (Sept. 15, 1997)) (standard under Sections 111 and 129 providing up to five-and-a-half years for commercial waste disposal to scale up to receive wastes diverted from the regulated medical waste generators).

[314] 88 Fed. Reg. at 33244.

[315] *See, e.g.*, Margaret R. Taylor, Edward S. Rubin & David A. Hounshell, *Control of SO_2 Emissions from Power Plants: A Case of Induced Technological Innovation in the U.S.*, 72 Tech. Forecasting & Social Change 697 (2005) (using qualitative and quantitative measures to show how regulation can stimulate innovation, using the rapid scale-up of FGD as a case study); *see also e.g.*, Jaegul Lee, Francisco M. Veloso, David A. Hounshell & Edward S. Rubin, *Forcing Technological Change: A Case of Automobile Emissions Control Technology Development in the US*, 30 Technovation 249 (2010) (finding that 1970s-era tailpipe emission standards drove automakers to develop innovative technologies that they otherwise would not have adopted, precisely because it was impossible to meet the standards with then-existing technologies, noting that technology-forcing has "influential power as the driver of technological innovation and adoption").

based limits.[316] EPA projects that about 108 GW of NGCC plants would be affected by the existing gas standards. Commenters' proposal to switch from a unit-based to a plant-based applicability for existing gas covers the portion of the existing gas fleet best suited for CCS retrofit. It would marginally increase the potential number of CCS projects compared with the proposal, while organizing such retrofits for maximum cost-effectiveness. Even for the relatively small number of EGUs subject to standards based on CCS or low-GHG hydrogen co-firing, owners and operators may comply with the standard in other ways.

EPA has modeled the projected amount of new control/fuel installations for the proposed BSER methods: CCS, natural gas co-firing, and hydrogen co-firing. EPA's modeling (Integrated Proposal) projects the following amounts of control technique installations resulting from *the combination of Inflation Reduction Act incentives* and the GHG rule's emission limits:

Table 8. Projections of CO_2 control installations under EPA modeling

Integrated Proposal	2030	2035	2040
Installed Capacity (GW)	**EPA Proposal**	**EPA Proposal**	**EPA Proposal**
Coal w/ CCS	12	12	9
Gas w/ CCS	5	9	9
Gas w/ hydrogen	0	42	12
Coal w/ gas co-fire	1	1	0

Commenters' modeling projects the following amount of control technique installations:

Table 9. Projections of CO_2 control installations under NRDC modeling

NRDC Modeling	2030	2035	2040
Installed Capacity (GW)	**EPA Proposal**	**EPA Proposal**	**EPA Proposal**
Coal w/ CCS	21	21	8
Gas w/ CCS	3	4	1
Gas w/ hydrogen	0	0	0

These projections include the projected effects of the incentives enacted in the IRA as well as the proposed emission limits. Accordingly, all of the installation work flowing from the combination of the IRA and EPA's rule is accounted for, making these numbers a conservative overestimate of the actual installations attributable to the EPA rule alone.

[316] For example, under Commenters' modeling of the Reference Case, 60 percent of the existing NGCC fleet is expected to operate under a 50 percent capacity factor by 2035. Under EPA's Proposal, this increases to 77 percent. Note that only a portion of the remaining capacity would meet EPA's capacity-based threshold (i.e., 300 MW unit or larger) and be subject to the emission guidelines.

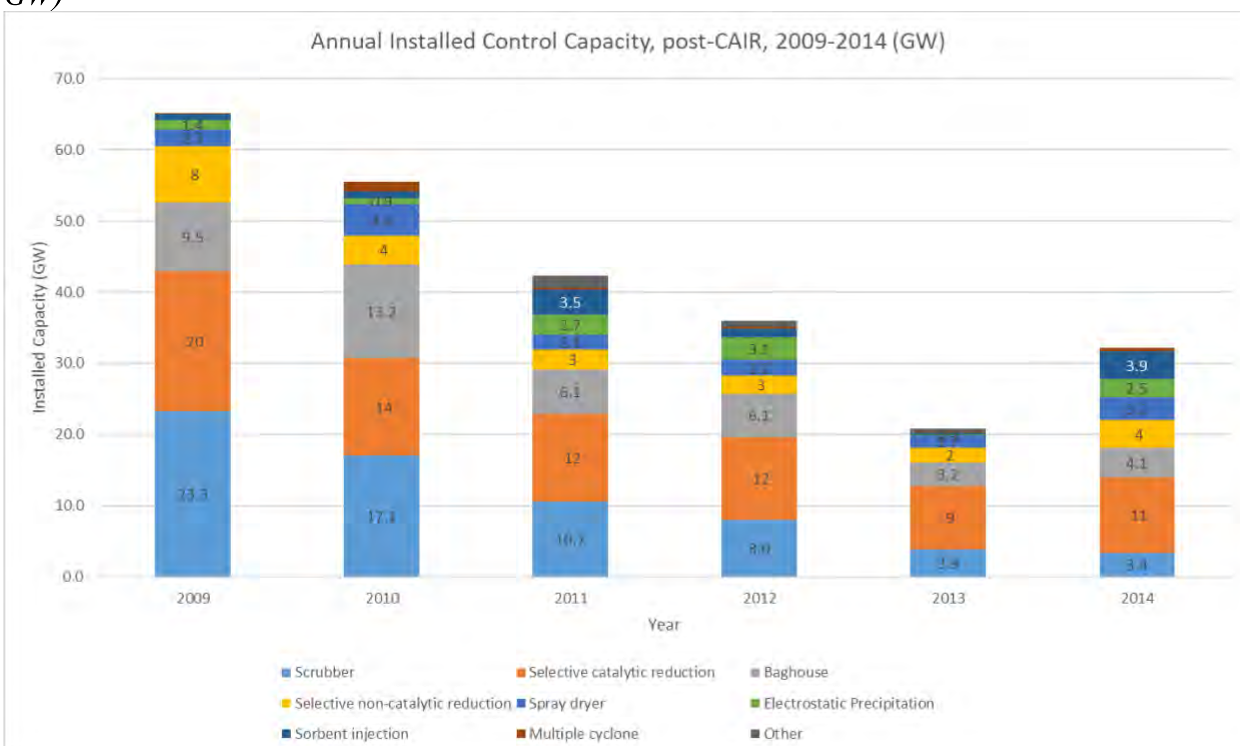
As discussed below, the projected amounts of pollution control installations during the compliance periods for the GHG rule are much less than the amounts of controls installed in previous recent EPA rules applicable to fossil EGUs. Likewise, the projected compliance costs in this proposal are lower than the costs the power sector has successfully managed under recent rules.

B. Clean Air Interstate Rule and Mercury and Air Toxics Standards

In 2005, EPA adopted the Clean Air Interstate Rule (CAIR), which required 28 States to submit plans to reduce emissions of NO_x, beginning in 2009, and SO_2 beginning in 2010.[317] The States' plans imposed emission limits on fossil electric generating units, resulting in massive amounts of control equipment installations for NO_x and SO_2 in the five-year period from 2009 to 2014. In addition, other programs required installation of particulate matter controls in the same period.

In 2009 and 2010 alone, while the CAIR rule was still being litigated, electric generators installed 65 GW and 56 GW of control equipment respectively. Over the five-year compliance period a total of 252 GW of generator capacity was equipped with newly retrofitted control equipment—far exceeding the capacity EPA projects to be controlled here.[318]

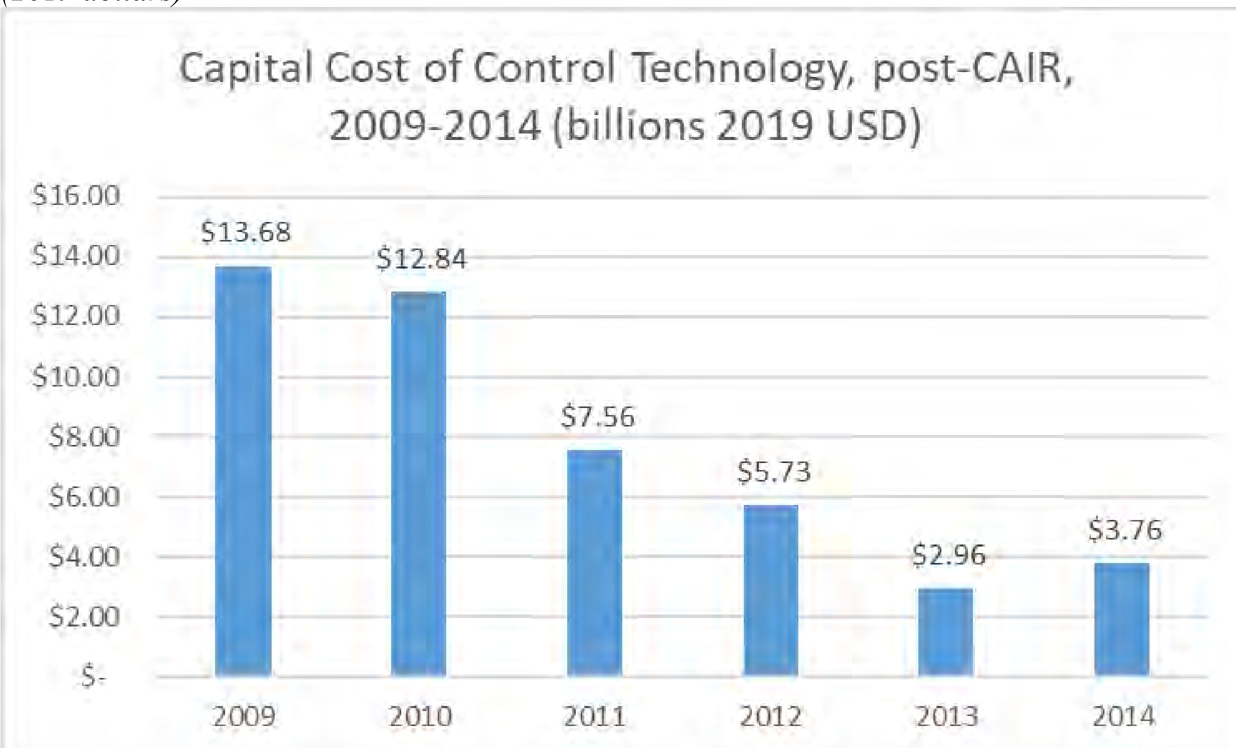
Figure 32. Annual Installation of Control Technology for CAIR Compliance (capacity covered in GW)[319]



[317] Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NOX SIP Call, 70 Fed. Reg. 25162 (May 12, 2005).
[318] *Compare* Figure 32, *infra*, with Tables 8 & 9, *supra*.
[319] Data obtained from EIA Form 860, calculations are appended.

As shown in Figure 33 below, power plant operators incurred more than $46 billion (2019 dollars) in capital costs to install SO_2 and NO_x control technologies between 2009 and 2014. More than half of that expenditure occurred in 2009 and 2010 alone, while several parties challenged CAIR in court.

Figure 33. Annual capital expenditures for control technology installed for CAIR compliance (2019 dollars)[320]



These capital expenditures *alone* shown in Figure 33 for CAIR exceed the *total* expected compliance costs for the proposal here—including, *inter alia*, capital costs, ongoing maintenance, recordkeeping, and associated CO_2 transportation costs—which EPA projects to be $11.2 billion in 2019 dollars for the period of 2024 to 2042.[321]

In another recent example, in 2012 EPA adopted the first version of the Mercury and Air Toxics Standards (MATS) establishing standards under Section 112 for mercury, and other air toxics emitted by EGUs, with a three-year compliance window.[322] This rule also was the subject of litigation, with a complex procedural history still ongoing today. Nevertheless, the industry was able to install massive amounts of control equipment in a very short period of time. As shown in Figure 34 below, in 2015 and 2016 alone, electric generators installed 68 GW and 72 GW of

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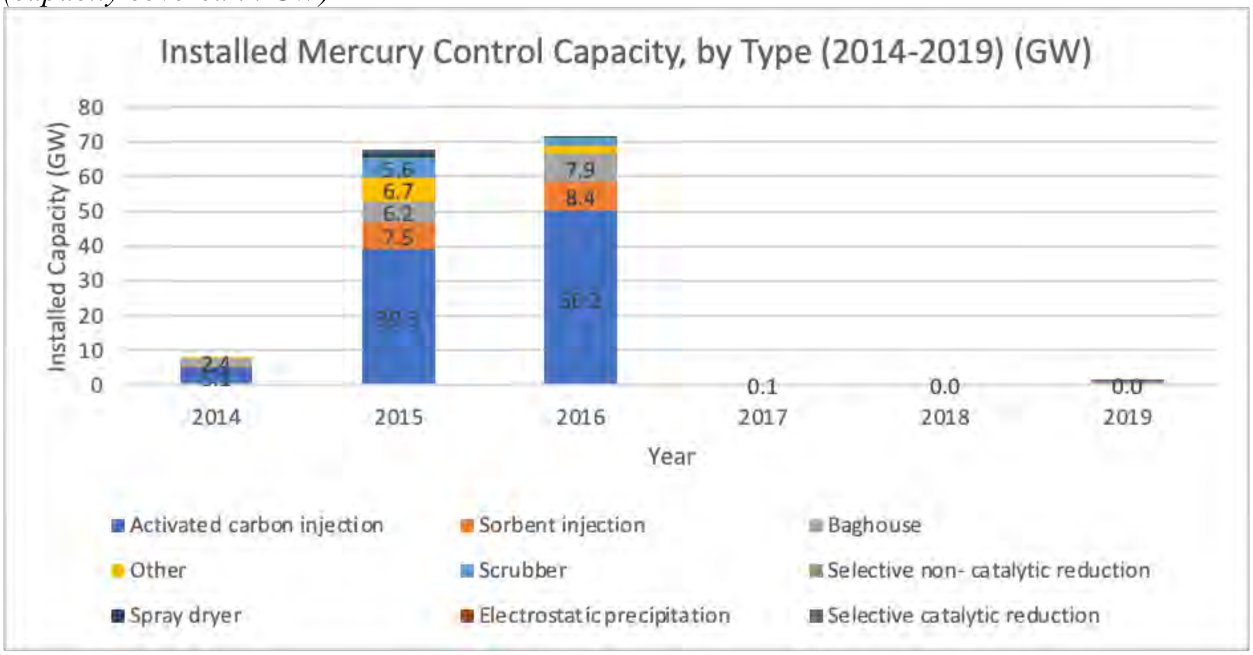
[320] Data obtained from EIA Form 860, calculations appended.
[321] Memo Supporting Integrated Proposal Modeling and Updated Baseline Analysis, *supra* note 297, at 8.
[322] National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial Institutional, and Small Industrial Commercial-Institutional Steam Generating Units, 77 Fed. Reg 9304 (Feb. 16, 2012).

control equipment respectively. In the five year period from 2014 to 2019, a total of 150 GW of generator capacity was retrofitted with new control equipment.

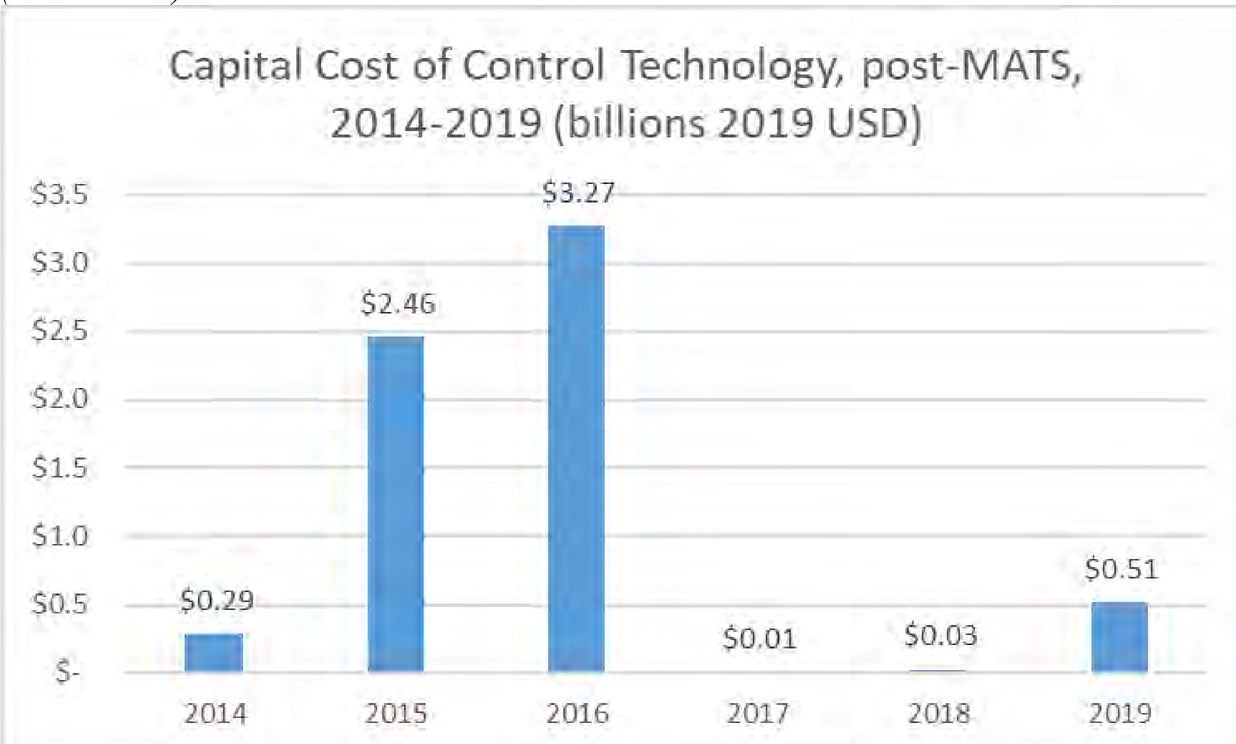
Figure 34. Annual Installation of Control Technology for Anticipated MATS Compliance (capacity covered in GW)[323]



As shown in Figure 35 below, power plant operators spent more than $6 billion (2019 dollars) to install the mercury control technologies shown in Figure 34. The bulk of this expenditure occurred in 2015 and 2016, which were the first years in which MATS generally required compliance.

[323] Data obtained from EIA Form 860, calculations appended.

Figure 35. Annual capital expenditures for control technology installed for MATS compliance (2019 dollars)[324]



In comparison to the massive, fast-paced power plant control equipment installation undertaken in relatively short time periods under CAIR and MATS, the scale of the installation work EPA projects here, considering the impact of *both* the IRA and this rule, is relatively modest and provides a longer lead time. The first compliance year under the rule is 2030, six years after the expected promulgation of the GHG rule. By 2030, modeling projects a total installation of retrofit control technology (including CCS, hydrogen co-firing, and gas co-firing at coal plants) covering only 18 GW (EPA) to 24 GW (NRDC). By 2040, the total projections rise to 58 and 112 GW, respectively, for NRDC and EPA's modeling. The controls installed over the 5-year compliance periods for CAIR and MATS dwarf these totals at 252 and 150 GW, respectively.

To summarize, the control technique installations and compliance costs projected to occur from the combination of the IRA legislation and EPA's GHG rule are only a fraction of what industry has already demonstrated it can achieve when complying with CAIR and MATS.

C. Flue-Gas Desulfurization and Selective Catalytic Reduction

EPA's regulations have provided the key driver to spur innovation across the power sector time and time again. In the 1970s, a few years after promulgating the first NSPS for SO_2 emissions from EGUs, EPA held a special public hearing with the utility industry to figure out why the available control technologies had not been deployed earlier. The agency found utilities had "generally lacked a real incentive to develop" scrubbers without emissions requirements and

[324] Data obtained from EIA Form 860, calculations appended.

lacked a "profit incentive to develop and install these systems."[325] Emissions standards provided that incentive, and results soon followed. When EPA first set SO_2 standards in 1971, there were only three commercial scrubber units operating on U.S. power plants and only one vendor of the technology.[326] By the end of that decade, there were 16 vendors providing the technology[327] and over 119 sulfur scrubbers had been installed.[328]

This rapid development and scale-up of FGD technology provides an apt analogy for the expected scale-up of CCS—which is itself a scrubber with similar characteristics to FGD. The rapid diffusion of FGD throughout the U.S. power sector followed a pattern of exponential growth triggered by successive, increasingly stringent limits on SO_x emissions.[329] When EPA adopted the first NSPS for SO_2 emissions from EGUs in 1971, it spurred rapid development and diffusion of FGD in new sources.[330] With the 1990 Clean Air Act Amendments' Acid Rain Program and associated SO_2 cap for existing EGUs, the diffusion of FGD expanded to retrofits.[331] From a starting point of zero installations and negligible patent activity before 1970, a majority of U.S. coal plants are now controlled by FGD.[332]

As another indicator, patent activity in SO_2 control technologies closely follows Congressional and EPA action, with notable spikes correlating to the 1977 Clean Air Act Amendments, the 1979 EGU NSPS, and the 1990 Clean Air Act Amendments.[333] And through learning-by-doing driven by these regulatory events, operational costs for FGD fell by roughly 83 percent for every doubling in capacity.[334]

Numerous studies and reports have found that diffusion and scale-up of CCS is likely to closely follow the path of FGD due to similarities in the regulatory regime, market conditions, and retrofits for post-combustion control technology.[335] The ample data available regarding diffusion

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[325] EPA, *National Public Hearings on Power Plant Compliance with Sulfur Oxide Air Pollution Regulations* 8 (Jan. 1974), https://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=9101OYM8.txt.
[326] *See* Margaret R. Taylor, Edward S. Rubin & David A. Hounshell, *Regulation as the Mother of Innovation: The Case of SO_2 Control*, 27 U. Den. L. 348, 360 tbl.2 (2005) (chronology of scrubber research, development, and design).
[327] *See id.* at 356.
[328] *See* EPA, *Press Release, EPA Says Scrubbers Necessary for Health Protection Under Coal Conversion Plan* (July 14, 1977), https://www.epa.gov/archive/epa/aboutepa/epa-says-scrubbers-necessary-health-protection-under-coal-conversion-plan.html.
[329] Stinjn van Ewijk & Will McDowall, *Diffusion of Flue Gas Desulfurization Reveals Barriers and Opportunities for Carbon Capture and Storage*, 11 Nature Commc'ns (2020) 11:4298, https://www.nature.com/articles/s41467-020-18107-2.
[330] *Id.* at fig. 1.
[331] *Id.*
[332] *Id.* (source data showing 0 percent of total U.S. energy capacity covered by FGD in 1970 and 52 percent by 2010, including both new installations and retrofits); Taylor et al., *supra* note 326, at fig. 6 (showing negligible patent activity before 1967).
[333] *See* Taylor, *supra* note 326, at figs.6 & 7.
[334] *Id.* at 713.
[335] *E.g.*, van Ewijk & McDowall, *supra* note 329; Varun Rai, David G. Victor & Mark C. Thurber, *Carbon Capture and Storage at Scale: Lessons from the Growth of Analogous Energy Technologies*, 38 Energy Policy 4089 (2010); Edward S. Rubin, David A. Hounshell, Sonia Yeh, & Margaret Taylor, *The Effect of Government Actions on Environmental Technology Innovation: Applications to the Integrated Assessment of Carbon Sequestration*

and costs for FGD systems (both in new construction and via retrofit) provide a compelling case study for projecting the scale up of CCS across the power sector. This literature demonstrates the importance of learning curves in driving down costs and ramping up deployment.[336]

The development of power sector NO_x control technologies followed a similar path to SOx control: stepwise diffusion closely trailing stringent regulatory demands. Early NO_x limits for stationary sources in the 1970s could largely be met with pre-combustion operational changes or combustion controls based on existing technologies such as flue gas recirculation and low-NO_x burners. Later regulations in the 1990s requiring deeper cuts necessitated the broader adoption of post-combustion controls such as selective catalytic reduction (SCR).[337] As with the development of FGD, patent activity in the area of NO_x control exploded in response to—and in anticipation of—more stringent regulations.[338]

Japan, Germany, and other European countries began to develop and deploy post-combustion NO_x controls more than two decades before the U.S. established NO_x limits that led to large-scale installation of SCR in the 1990s.[339] This is reflected in the rise of patent activity overseas versus domestically: Japan and Germany saw a rapid increase in innovation in the 1970s and 1980s when their respective regulatory regimes were introduced, while the U.S. had a corresponding bump when more stringent NO_x regulations came into place in the 1990s.[340] Because the domestic power sector did not have the pressure of stringent NO_x regulations prior to 1995, hardly any post-combustion controls were installed. But, once that regulatory pressure was applied, industry rapidly sprang into action and SCRs are now installed at 79 percent of regulated units.[341] The story of post-combustion NO_x controls confirms that more stringent regulation creates the more rapid technology scale-up.[342]

D. Combined Cycle Gas Units

And, of course, it is impossible to talk about rapid diffusion and deployment in the power sector without discussing the transition from coal to gas.

Technologies (2004), https://www.osti.gov/servlets/purl/825164-w6B8uh/native/; Stephen Healey, *Scaling and Cost Dynamics of Pollution Control Technologies: Some Historical Examples, IIASA Interim Report* (2013), https://core.ac.uk/works/25674799.

[336] *See* Keywan Riahi, Edward S. Rubin, Margaret R. Taylor, Leo Schrattenholzer & David Hounshell, *Technological Learning for Carbon Capture and Sequestration Technologies*, 26 Energy Economics 539, 562 (2004) (using FGD to develop a learning curve for CCS and concluding that "climate policy models should be capable of characterizing future changes in cost and performance resulting from technology innovation (learning)").

[337] Sonia Yeh, Edward S. Rubin, Margaret R. Taylor & David A. Hounshell, *Technology Innovations and Experience Curves for Nitrogen Oxides Control Technologies*, 55 J. Air & Waste Mngmt. Ass'n 1827 (2005), DOI:10.1080/10473289.2005.10464782.

[338] *Id.* at 1831, fig.3.

[339] *Id.* at 1836-37.

[340] *Id.* at 1837 ("In both instances, these eras of surging innovation corresponded with periods in which stringent regulations were being imposed in those countries. In contrast, no analogous increase in U.S.-based activity in postcombustion controls was observed during that period, consistent with the lack of regulations that required such technology at the time. These findings lend additional support to the link between regulatory stringency and the direction of environmental control technology innovation.").

[341] EPA, *Progress Report: Emission Controls and Monitoring*, https://www3.epa.gov/airmarkets/progress/reports/emission_controls_and_monitoring_figures.html#figure3

[342] *Id.*

An examination of the 2000s reveals just how swift the deployment of NGCC operations was. NGCC nameplate capacity additions between 2000 and 2006 totaled approximately 150 GW, or over 21 GW per year on average.[343] This rate peaked in 2002 and 2003, where an average of nearly 41 GW were added per year.[344] In comparison, the 1990s saw additions of just under 28 GW *in total*, or around 2.8 GW per year on average.[345]

Indeed, the elevated deployment of NGCC wasn't just rapid, it was practically instantaneous. The first year of the "boom," 2000, saw 11.6 GW of additions, compared to only 2.0 GW the year before—an increase of more than five-fold. Furthermore, the rate of NGCC capacity additions at its peak in 2002 was around 42 GW, compared to only 2 GW in 1999, the last year before the boom and only three years earlier—representing more than a 20-fold increase. This level of natural gas infrastructure deployment is consistent with the 30 to 44 GW average annual capacity additions for renewable energy buildout projections over the next fifteen years, and exceeds anticipated CCS deployment in the power sector.[346]

Likewise, the direct conversion of coal plants to gas was also rapid. Between 2011 and 2019, 121 coal-fired power plants were repurposed to burn other types of fuel, 103 of which installed new technology to accommodate natural gas.[347] Indeed, installed coal capacity decreased from 316.8 GW in 2010 to 267.6 GW in 2019.[348]

An examination of U.S. gas pipelines further illustrates the deployment of gas in the power sector. U.S. total gas pipeline mileage increased 84,114 miles from 2004 to 2010, averaging 17,480 miles of pipeline expansion per year.[349] As of 2021, gas pipelines span 1,659,645 miles across the U.S.[350] Even examining the transmission subset of gas pipelines, over 25,000 miles were built between 1997 to 2008.[351] In replicating the construction effort of transmission pipelines, power plants could capture 1,000 million metric tons per year of CO_2 emissions with a similar length of pipeline.[352]

The regulated industry thus is no stranger to installing new technology to meet new goals or requirements. Its demonstrated record of adaptability serves to show that whether change is needed in response to market forces or regulations, speedy buildouts have been characteristic of the power sector and will continue to be.

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343 *See* EIA, *Form EIA-860 detailed data with previous form data (EIA-860A/860B)* (Aug. 5, 2020), Electricity, https://www.eia.gov/electricity/data/eia860/.
344 *See id.*
345 *See id.*
346 See *supra* Sec. VI.D.
347 EIA, *More than 100 coal-fired plants have been replaced or converted to natural gas since 2011* (Aug. 5, 2020), https://www.eia.gov/todayinenergy/detail.php?id=44636.
348 *Id.*
349 *See U.S. Oil and Gas Pipeline Mileage*, Bureau Transp. Stat. (BTS), https://www.bts.gov/content/us-oil-and-gas-pipeline-mileage (last visited Aug. 4, 2023).
350 *Id.*
351 88 Fed. Reg. at 33369 (citing EIA, *Natural Gas Pipeline Projects* (July 28, 2023), https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx).
352 *Id.* (citing Richard Middleton et al., *Reaching Zero: Pathways to Decarbonize the US Electricity System with CCS*, 16th Int'l Conf. on Greenhouse Gas Control Technologies at 28 (2022), https://ssrn.com/abstract=4274085).

VIII. Reliability/Resource Adequacy

The impacts on the source category from this proposal as well as Commenters' recommendations for improvements are modest and manageable. The proposal—its subcategories and emission limits—are keyed to the trends and trajectory of the source category, the availability of large tax incentives, and the generous timelines allow for planning, permitting, construction and infrastructure buildout. This design ensures reliable and clean operation of fossil fuel-fired EGUs.

As discussed above in Sec. IV.A, the increase in domestic natural gas production and sustained low prices, along with advances in the competitiveness of renewable energy generation, have been the major drivers of the changes in the U.S. power sector generation and technology mix in the last two decades. Since then, grid operators, utilities and regulators have been continually adjusting their planning and operational practices to ensure that ongoing changes in the sector do not threaten power system reliability and resource adequacy. They now have the benefit of large incentives enacted by Congress to assist them. In designing this proposal, EPA properly took into account the underlying trends that precede the proposal and will continue with or without it.

The power industry's many stakeholders are well-organized and strongly oriented towards a safe and reliable operation of the U.S. power system. There are well-established and effective procedures, regulations and enforceable standards in place to ensure reliability of the system. These layers of security have a long history of incorporating environmental standards while maintaining a resilient and reliable grid.

Among the many "business-as-usual" procedures include:[353]

- Specific roles and responsibilities assigned to different organizations, such as NERC, regional reliability organizations, grid operators, power plant and transmission owners and regulators;
- Proactive planning processes that foresee the actions and resources needed to make sure the system is capable to run in a reliable way;
- Secure communication systems, operating protocols, and real-time monitoring processes to alert participants to any issues, and perform corrective actions when needed.
- A system of reserves, asset redundancies, and individual and collective back-up action plans that automatically run when some part of the system has a problem.

The proposal was developed taking into account its potential impacts on the rapidly evolving power sector, including a robust development process that incorporated comprehensive input from various stakeholders, including power generating companies, grid operators, and state and federal regulators. The EPA conducted a Resource Adequacy Analysis using the IPM to support its ruling proposal.

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[353] Susan Tierney et al., The Analysis Group, *Electric System Reliability and EPAs Clean Power Plan: Tools and Practices* (2015), https://www.analysisgroup.com/globalassets/content/insights/publishing/analysis_group_clean_power_plan_miso_reliability.pdf.

In EPA's analysis, operational generating capacity to provide electricity remains similar between the base IRA scenario and the policy scenario.[354]

- The model incorporates criteria to ensure that projected retirements are managed by using existing surplus reserves, new builds, and adjusting transmission flows between regions according to changes in the generation mix.
- In the model, reserve margins are used to represent the reliability standards in effect in each NERC region. These requirements ensure that each model region in IPM (67 total) has adequate capacity to meet peak demand and additional reserve margins.
- For 2030, there is an increase of 3.8 GW of natural gas-fired generating capacity, and 1.1 GW for solar and wind, compared to the baseline.
- By 2035, coal retirements increase by 22 GW, but are mainly offset by 24.1 GW of natural gas-fired generating capacity additions and 2.4 GW of renewable additions.
- By 2040, coal retirements decrease to 17 GW, indicating a movement towards a steady level of remaining coal capacity.
- While these estimates represent total installed capacity, region-specific capacity credits are considered for variable technologies like solar and wind to maintain target reserve margins. Therefore, resources like variable renewables are derated relative to their nameplate capacity when accounting for reserve margin.

The proposal was also a product of consultation with DOE and FERC on electric reliability.[355] This commitment to strengthening communication and collaboration was recently memorialized through the DOE-EPA Joint Memorandum of Understanding, signed on March 8, 2023.[356] The MoU will support consistent and informed consultation on electric reliability issues, and ensure a proactive approach to addressing the potential challenges of the evolving power system with the insurance of a high standard of reliable electric service for all customers.

Altogether, these measures result in a balanced and robust electricity network that takes into account environmental responsibility and the practical realities of maintaining a reliable and adequately resourced power system.

In light of the proposal's design features, EPA's analysis of its impacts, and the agency's close collaboration with stakeholders on reliability, we support EPA's assessment that the proposed rules combined with the reliability assurance safeguards outlined below, can be implemented while simultaneously assuring reliable provision of electricity fully sufficient to meet demand.

A. EPA's Proposed New Source Performance Standards and Emission Guidelines Will Not Pose a Threat to Grid Reliability

Two studies modeling operation of the U.S. grid demonstrate viable pathways for maintaining grid reliability while curbing emissions under EPA's proposal:

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[354] EPA, *Technical Support Document: Resource Adequacy Analysis* (Apr. 2023), Docket ID No. EPA-HQ-OAR-2023-0072-0034 (2023) [hereinafter *Resource Adequacy Analysis TSD*], https://www.epa.gov/system/files/documents/2023-05/Resource%20Adequacy%20Analysis%20TSD.pdf.
[355] 88 Fed. Reg. at 33247.
[356] *See* EPA & DOE, *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* (March 8, 2023), https://www.epa.gov/power-sector/electric-reliability-mou.

- NREL's 2022 Standard Scenarios Report: "A U.S. Electricity Sector Outlook" and associated "Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System" explicitly model reliability constraints in the capacity expansion modeling using the Regional Energy Deployment System (ReEDS) to understand the impact of the IRA on power sector build-out, without specific emissions limits; and
- The UC Berkeley 2035 Study, which also uses ReEDS and leverages its reliability constraints, models reliable portfolios for a grid with 90 percent clean electricity by 2035 by assessing projected grid performance through years of hourly weather data, including extreme events and includes specific constraints on emissions.

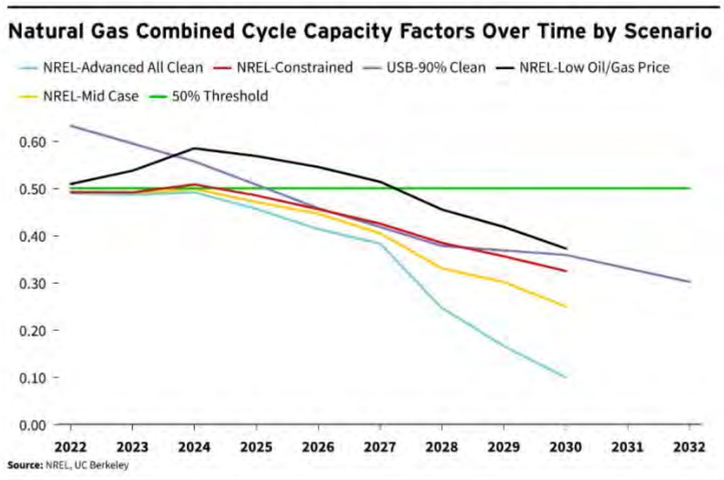
These studies, with results driven by least-cost grid planning models, show that the EPA's proposed approach to limiting emissions from new and existing gas-fired units by capacity factor-based subcategories does not pose a threat to grid reliability. Instead, EPA's proposed rule ensures that gas plants can maintain operations consistent with least-cost planning pathways that inherently ensure resource adequacy, with built-in margins. The range of scenarios evaluated in the NREL study make these results robust even under conservative planning assumptions about future transmission development, renewable development site availability, and CO_2 transport infrastructure.

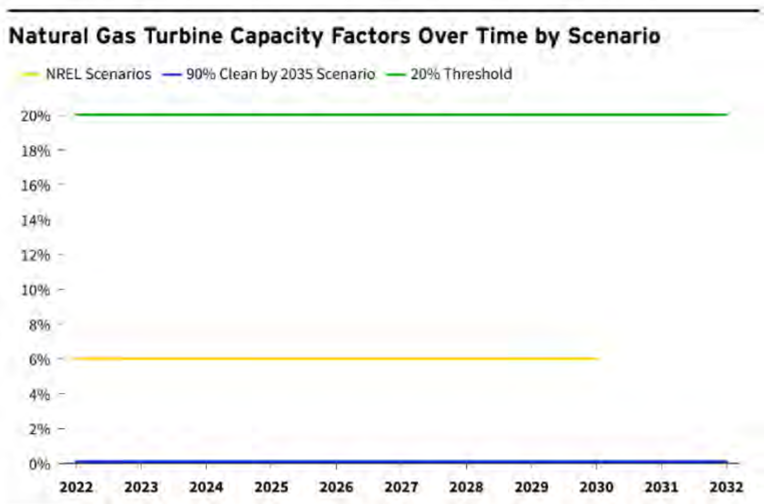
B. The Proposed Standards for New and Existing Gas Will Result in Plant Operations That Are Consistent with a Reliable, Least-Cost, Low-Carbon Grid

In the two selected grid planning studies led by researchers at NREL and UC Berkeley, researchers used advanced grid planning models to identify resource portfolios that maintain reliability while transitioning to a lower carbon resource mix. We focus on these two studies because they: (1) are roughly aligned with current expectations for the pace of grid decarbonization post-IRA, and (2) they provide information on how gas capacity factors are expected to change in those scenarios over time.

In both studies, gas capacity factors for both combined cycles and simple cycle CTs decline to well-below today's levels by 2032 while maintaining today's high standards for reliability and resilience. These studies demonstrate that it will not be necessary to operate gas generators at capacity factors higher than the capacity factors of the proposed subcategories to maintain grid reliability, as variable renewable generation increases substantially.

Figure 36. Comparison of Capacity Factors of Natural Gas Combined Cycle and Simple Cycle Combustion Turbines Across Grid Planning Studies





1. National Renewable Energy Laboratory IRA-BIL [IIJA] Scenarios

In a major national study led by NREL, all scenarios evaluated show gas combined cycles and simple cycle CTs nationwide running at average annual capacity factors by 2032 that are below the capacity factor subcategory threshold in the proposal that would put them into the baseload subcategory (in the case of combined cycles) or the intermediate subcategory (in the case of simple cycle CTs), and thus subject to more-stringent standards. This study specifically reflects outcomes showcasing the potential impacts of the IRA and the IIJA—referred to by NREL as the BIL—on the U.S. power sector.[357] NREL uses the Regional Energy Deployment System capacity expansion model and builds on preliminary results from the 2022 Standard Scenarios Report, incorporating the expected impacts of the new federal legislation.[358] The ReEDS model

[357] Daniel Steinberg et al., NREL, *Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System* (2023) https://www.nrel.gov/docs/fy23osti/85242.pdf.
[358] NREL, *2022 Standard Scenarios Report: A U.S. Electricity Sector Outlook* (2022), https://www.nrel.gov/analysis/standard-scenarios.html.

requires that demand is served nationwide and regionally, and does not allow for lost load. Instead of modeling hourly chronological operations, it requires sufficient supply and demand resources to meet forecasted load across seventeen "time slices", which capture representative daily and seasonal variations in load as well as a summer "superpeak" that represents the top 40 hours of summer load. ReEDS accounts for reliability through planning reserve margin constraints, and the Standard Scenarios report notes that "by the end of the 2020s, the ReEDS model has all regions exactly meeting the NERC-recommended planning reserve levels." As a least-cost optimization model, ReEDS will not procure capacity above NERC-recommended Planning Reserve Margin levels, which are hard-coded into the model, unless doing so further minimizes costs subject to other model constraints. The NREL scenarios outlined in the figure below of results are as follows:

- IRA-BIL, Mid-Case: a scenario that includes the IRA and BIL provisions and assumes increased load growth consistent with a scaled version of the Moderate Electrification scenario from the 2018 NREL Electrification Futures Study. Cost and performance assumptions for renewable energy technologies are from the NREL ATB 2022 Moderate case and plant level CCS retrofit costs and performance impacts are from the EIA's - National Energy Model System (NEMS) model.
- IRA-BIL, Constrained: A scenario with the same assumptions as the "IRA-BIL-Mid" case, except there is reduced land area/resources available for renewable development (applies to wind, solar, geothermal, and biomass). New long-distance transmission builds are restricted to the historical national average build rate (1.4 TW-mi per year) and to builds within transmission planning regions. Includes increased (2x) cost of CO_2 pipeline, injection, and storage infrastructure.
- IRA-BIL, Low Oil/Gas Price: A scenario with the same assumptions as the "IRA-BIL-Mid" case, except natural gas prices are from the EIA's 2022 AEO High Oil and Gas Resource case.
- Advanced All Clean Technologies: A scenario with cost and performance assumptions for battery storage, renewable, nuclear, and greenfield CCS technologies are from the NREL ATB 2022 Advanced Case, representing more rapid technology cost declines.

Although NREL's analysis includes additional scenarios, the "Low Oil/Gas Price" and "Advance All Clean" scenarios represent "bookend" cases on the average annual capacity factors of NGCCs; that is, the average annual capacity factors of combined cycles in all other scenarios fall somewhere between those from these two cases. The Advanced All Clean scenario shows the largest decrease in capacity factors for combined cycles, which fall to about a 10 percent average annual capacity factor by 2032 while still meeting the model's reliability constraints. Even in the scenario most favorable to fossil fuel generation, the Low Oil/Gas Price scenario, fleetwide combined cycle average annual capacity factors fall below the 50 percent threshold by 2028. NREL enforced a requirement in its modeling that simple cycle CTs operate at at least a 6 percent minimum average annual capacity factor to ensure that simple cycle CT utilization is aligned with empirical trends. The model kept simple cycle CT operations at this minimum required level. With or without this requirement, the model's reliability constraints drive sufficient capacity build out to ensure reliable operations across all periods modeled.

Notably, NREL also models a "constrained" scenario with several conservative assumptions, including not allowing transmission development to exceed historical averages, reduced available land area for renewable energy development, limits on CO_2 pipeline injection and storage infrastructure, and more. Even this scenario shows fleetwide operations of combined cycles at average annual capacity factors below the threshold that would place them in the baseload subcategory subject to more stringent requirements in the EPA's proposed rule for all years except 2024, where average annual capacity factors exceed 50 percent by a slight margin.

The results from the IRA-BIL-Mid case show how reliability conditions can be maintained through accelerated buildout of clean energy resources, especially wind, solar and battery storage, while contributions from NGCCs and coal plants fall over time.[4]

Figure 37. Capacity and Generation from Various Resources Across Scenarios Examined in NREL IRA-BIL Study[359]

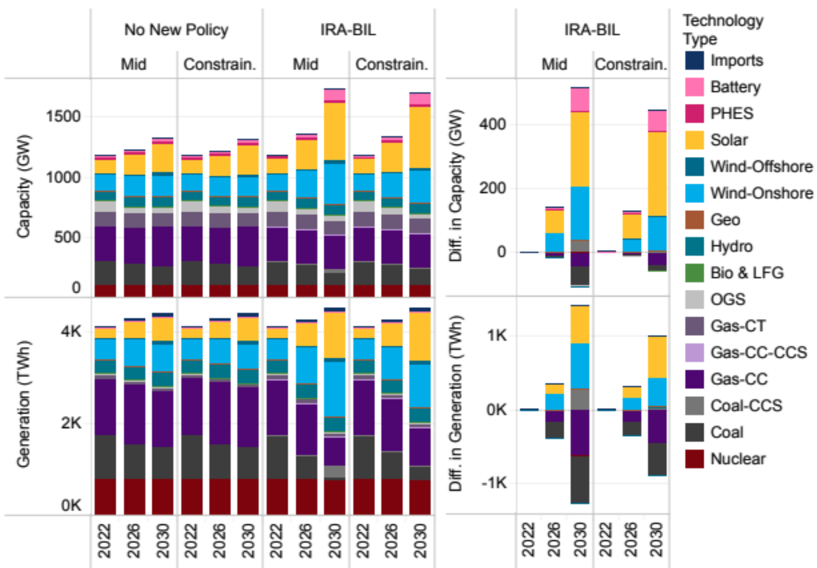


Figure 1. Left pane: capacity (top row) and generation (bottom row) 2022-2030 by technology in the Mid and Constrained *No New Policy* and *IRA-BIL* cases. Right pane: differences in capacity and generation in the *IRA-BIL* Mid and Constrained cases from the corresponding No New Policy case.

2. University of California-Berkeley 2035 Report Scenario

In a major national study released in 2020, researchers at UC Berkeley evaluated pathways towards a 90 percent clean grid nationwide by 2035.[360] Like NREL's study, the "2035 Report" also uses the ReEDS capacity expansion model to identify resource planning pathways, and utilizes several of the same data sources, including the NREL ATB projections for technology costs and fuel prices from the EIA's AEO. In addition to the reliability constraints built into the ReEDS model, the 2035 Report evaluates reliability during extreme events by requiring the model to meet hourly demand across all hours over seven consecutive years (2007 to 2013), including periods of extreme weather. Although this study was performed before passage of the

[359] Steinberg et al., *supra* note 357.
[360] Goldman School of Pub. Pol'y, Univ. Cal. Berkeley, *2035 Report: Plummeting Solar, Wind, and Battery Costs Can Accelerate Our Clean Electricity Future* (2020), http://www.2035report.com.

IRA and IIJA, its results are still useful in helping us understand the role of natural gas plants in a transitioning grid.

Like the NREL study, the 2035 Report shows a comparative increase in generation provided by solar and wind resources, and declining generation from coal and natural gas. Further, the 2035 Report provides a detailed analysis of the role of natural gas in its central "90% Clean" case. For NGCCs, the capacity factors start higher than the reported national average at the beginning of the study, but by 2024 are within the range of the NREL analysis scenarios. Unlike NREL, UC Berkeley ran the ReEDS model without a minimum capacity factor requirement for simple cycle CTs, which resulted in average annual capacity factors of less than 1 percent for these generators. The model was able to reliably meet demand across 7 years of historical data in hourly production cost simulations as part of the study's extreme event analysis.

By 2035, only 361 GW of gas capacity is needed, about two thirds the size of the existing U.S. gas fleet at the time of the study's publication. Around 70 GW (or around 19 percent) of this capacity is dispatched less than 1 percent of annual hours on average. The authors also noted that the model did not include likely lower-cost options, which could be dispatched as well to meet reliability, such as demand response and customer-sited generation.

Figure 38. National Generation Mix (2020 to 2035) for the central 90% Clean case in University of California-Berkeley 2035 Report Scenario[361]

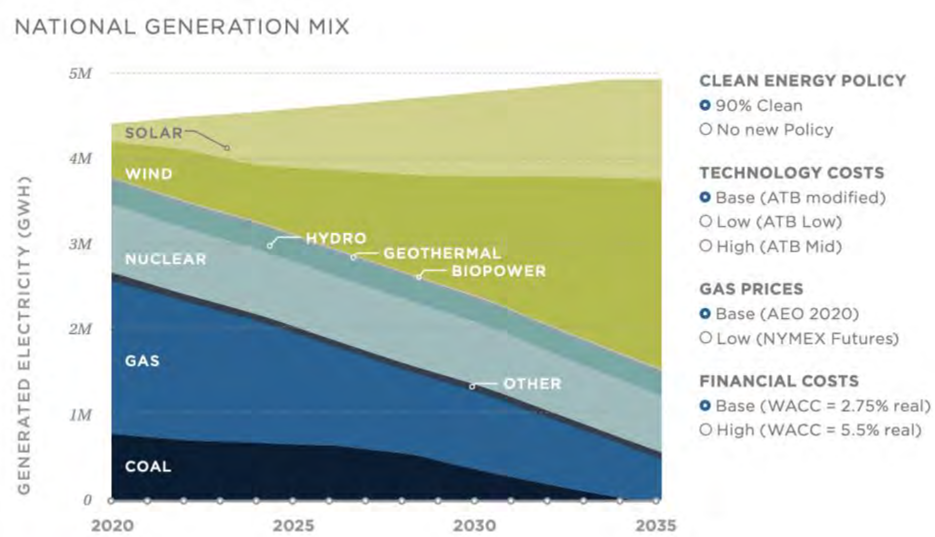


FIGURE 6.

National Generation Mix (2020-2035) for the central 90% Clean case

361 *Id.*

3. These Studies Take Different Approaches, but Both Demonstrate That Gas Capacity Factors Are Likely to Continue to Decline as They Support a Clean, Reliable Grid

Both the NREL study and 2035 Report apply leading practices in long-term grid modeling to evaluate the evolution of America's bulk power system. Although both studies had a different purpose—the NREL study evaluated the impacts of the IRA-BIL on the U.S. power system, while the 2035 Report evaluated pathways to a national grid mix that meets 90 percent clean electricity share by 2035—their results tell a similar story. As the alignment across the results of the two studies show, least-cost investment pathways that incorporate the impacts of the IRA-BIL are also clean planning pathways. In this future, utilization of natural gas power plants also declines compared to present day levels, and falls well under the subcategory division lines in the proposal within this decade across all scenarios. This lower utilization does not come at the expense of reliability. By specifically including reliability constraints aligned with federal standards, these studies ensure that scenarios evaluated are consistent with these standards. Building a clean, reliable grid is not just good for the climate—it is the least-cost pathway. Based on these projected changes in the power sector, the EPA's proposed regulations would allow most gas units to comply with modest changes, while ensuring that those few combined cycles that choose to operate at baseload and simple cycle CTs at intermediate load meaningfully control their climate pollution using demonstrated, cost-effective technologies.

C. The Proposed Rule Is Designed to Respond to Any Reliability Concerns

The proposed rule includes critical design features that allow the power system operational flexibility and facilitate long-term planning. The provisions, such as the varied stringency of performance standards by capacity factor and operational horizon, offer a differentiated approach to regulation that recognizes the heterogeneity of existing and future power generation assets.[362] In addition, the proposal provides compliance deadlines and State plans sufficient flexibilities. This aspect of the rule design allows asset owners and operators ample lead time to plan a smooth transition while maintaining the system's reliability.[363]

Another layer of flexibility in the rule is EPA's ability to exercise enforcement discretion under certain unforeseen circumstances, allowing covered EGUs and grid operators to maintain reliability and avoid disruptions to the power supply. States can also apply less stringent standards through the RULOF variance process on the basis of an unalterable condition that is not within the designated source's control, such as technical infeasibility, space limitations, water access, or geologic sequestration access.

In addition to these safeguards in the state planning process, states will be free to submit SIP revisions to EPA seeking extended increments of progress and compliance deadlines where existing sources encounter bona fide difficulties in implementing their selected control strategies, such as CCS or hydrogen co-firing.[364] For instance, a source might be unable to construct a CO_2

[362] *Id.*
[363] *Id.*
[364] *See* 88 Fed. Reg. at 33403-05; *cf.* 87 Fed. Reg. at 79201 (proposed rule contemplating a SIP revision where a source's circumstances change by increasing operation, possibly warranting a different variance).

pipeline as planned, or secure sufficient supplies of low-GHG hydrogen despite best efforts. Arguably, sources in those circumstances would have run into problems that qualify as factors fundamentally different from the factors that EPA considered in establishing the emission guideline, warranting extended increments of progress or compliance schedules under the RULOF provision of Section 111(d).[365] If EPA were not able to evaluate and approve the SIP revision in time to ensure grid reliability, states or sources could seek an administrative compliance order (ACO) from EPA, adhering to the requirements in EPA's emission guidelines.[366] Finally, if EPA were not able to evaluate a request for an ACO in time to address the emergency, companies or states could request a Federal Power Act Section 202(c) order from DOE allowing the source to run for 90 days, with the possibility of renewal after consultation with EPA.[367]

In no event, however, should EPA build into the emission guideline automatic provisions that a state could invoke at will to exempt sources from the requirements of an approved plan; extensions of increments of progress, milestones, or compliance dates and/or relaxation of standards must ordinarily be effectuated through a SIP revision to allow for public input and EPA review.[368] Nor should EPA lightly approve SIP revisions or grant ACOs that would alter milestones for sources on the path to retirement, as owners and operators would have had sufficient time to secure replacement generation. Further, EPA need not address issues with new sources that encounter difficulties in deploying CCS or hydrogen co-firing, as new sources have the ability to site near CO_2 storage or hydrogen supplies and avoid such difficulties.[369]

EPA notes that while some EGU owners might find it more cost-effective to retire and replace their units with cleaner ones rather than investing in new emissions controls, owners are required to go through procedures set by the regional transmission organizations, balancing authorities, and state regulators to protect system reliability.[370]

These processes typically assess the potential impacts of the proposed EGU retirement on the system reliability, and identification of options for mitigating any adverse impacts. Even in some

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[365] *See* 42 U.S.C. § 7411(d)(1).
[366] We urge EPA to include those requirements and criteria for issuing an ACO in its binding emission guidelines, so that companies, states, and EPA itself have clear expectations and guardrails around issuing ACOs. See 88 Fed. Reg. at 33402 (requesting comment on this issue).
[367] *See* 16 U.S.C. § 824a(c); *see also* 88 Fed. Reg. at 33416 (discussing this possibility).
[368] *See* proposed 40 C.F.R. § 60.23a(1) (requiring meaningful engagement with pertinent stakeholders on plan revisions).
[369] EPA has proposed to retain the exclusion of electric sales that result from system emergencies from the net electric sales that determine a new gas unit's subcategory. See 88 Fed. Reg. at 33333; proposed 40 C.F.R. § 60.5580a (defining "Net-electric sales" to exclude "Electric sales that result from a system emergency"). The emission guidelines for existing CTs do not appear to provide a similar exclusion of operating hours or heat input that results from system emergencies. *See* proposed 40 C.F.R. § 60.5850b(a) (excluding units "that operate at an annual capacity factor equal to or less than 50 percent"); *id*. at proposed § 60.5880b (defining "Annual capacity factor" as "the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating"); *see also* 88 Fed. Reg. at 33415 ("[U]nits that operate below 50 percent capacity factor annually (and are not subject to the CCS requirement) would still be able to operate at higher levels during times of greater demand, thereby maintaining their capacity accreditation values."). EPA should consider excluding from a unit's annual capacity factor any heat input that resulted from system emergencies.
[370] *See* 88 Fed. Reg. at 33415-16.

cases where short-term mitigation options are not available, there is provision of revenues to support EGUs' continuing operation until longer-term measures are available. The EPA also anticipates that any subsequent unit retirement will be conducted in the customary orderly manner, where regional transmission organizations, balancing authorities, and state regulators exercise their authority to safeguard the reliability of the electric system.

IX. Co-Pollutants, Cumulative Impacts, and Community Protections

We support the agency's efforts to uphold equity and environmental justice principles within the proposal, as well as its steps taken to consider the impacts of the proposed rule on disadvantaged communities. Low-income communities and communities of color are disproportionately overburdened by air pollutants from sources such as oil and gas facilities[371] and fossil EGUs contribute to health impacts in those communities, including health risks from asthma, cancer, cardiovascular disease, and other negative health outcomes.

EPA and this administration have made commendable commitments to address this pattern of inequitable pollution burdens.[372] For example, EPA has "committed to making equity, environmental justice, and civil rights a centerpiece of the agency's mission."[373] This administration's commendable commitment to environmental justice comes alongside the recognition that, "[f]or decades, EPA, state environmental regulators, and local zoning officials have made decisions that contributed to the disproportionate pollution burden on people of color and underserved communities across the country …."[374] In order to alleviate these burdens, this administration has actively promoted environmental justice measures across agencies.[375]

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[371] Lesley Fleischman & Marcus Franklin, *Fumes Across the Fence-Line: The Health Impacts of Air Pollution from Oil & Gas Facilities on African American Communities* (Nov. 2017), http://www.catf.us/wp-content/uploads/2017/11/CATF_Pub_FumesAcrossTheFenceLine.pdf

[372] *E.g.*, Executive Order 14008: Tackling the Climate Crisis at Home and Abroad, 86 Fed. Reg. 7,619 (Jan. 27, 2021) [hereinafter E.O. 14008] (directing EPA to "assess whether underserved communities and their members face systemic barriers in accessing benefits and opportunities available pursuant to EPA's policies and programs"); Email from Michael S. Regan, Administrator, EPA, to all EPA employees (Apr. 7, 2021), https://www.epa.gov/sites/default/files/2021-04/documents/regan-messageoncommitmenttoenvironmentaljustice-april072021.pdf (issuing a notice to all EPA offices to "take immediate and affirmative steps to incorporate environmental justice considerations into their work, including assessing impacts to pollution-burdened, underserved, and Tribal communities in regulatory development processes and considering regulatory options to maximize benefits to these communities").

[373] EPA, E.O. 13985 Equity Action Plan, 2 (April 2022), https://www.epa.gov/system/files/documents/2022-04/epa_equityactionplan_april2022_508.pdf.

[374] *Id.* at 4.

[375] *See, e.g.*, E.O. 14008, *supra* note 372 ("To secure an equitable economic future, the United States must ensure that environmental and economic justice are key considerations in how we govern. That means investing and building a clean energy economy that creates well-paying union jobs, turning disadvantaged communities—historically marginalized and overburdened—into healthy, thriving communities, and undertaking robust actions to mitigate climate change while preparing for the impacts of climate change across rural, urban, and Tribal areas. Agencies shall make achieving environmental justice part of their missions by developing programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related, and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts.").

And EPA has committed to prioritize "tak[ing] decisive action to advance environmental justice and civil rights."[376] In doing so, the agency aims to "advance the promise of clean air, clean water, and safe land to the many communities across the country that have not received the full benefits from EPA's decades of progress."[377] Advancing environmental justice efforts "is especially important in an era when EPA must simultaneously break the cycle of history environmental injustices while maximizing protection for these same communities as they are too often hit worst and first from the impacts of a changing climate."[378]

This administration and its EPA have made long overdue public commitments to environmental justice communities who have borne decades of air and water pollution for the reasons that EPA has recognized. Given these commitments, it is therefore imperative that the proposed rule and its implementation at the state level do not worsen, and wherever possible will reduce, those burdens.

A. Co-Pollutants

While the proposed rule is focused on reductions in GHG emissions, it is important to take into consideration any additional expected impacts from sources' compliance decisions. On a nationwide basis the proposed rule projects substantial reductions in emissions of CO_2 and co-pollutants such as SO_2, $PM_{2.5}$, and NO_x.[379] But the proposal also projects differing effects at a local level, with co-pollutant concentrations declining in many locales but potentially increasing in some other areas.[380] Co-pollutants like NO_x, $PM_{2.5}$, SO_2, and hazardous air pollutants will decline at fossil fuel-fired EGUs that decrease generation, as well as those units that retire. Moreover, SO_2 emissions are expected to decrease substantially from any coal plants that install

[376] *FY 2022-2026 EPA Strategic Plan*, EPA, 26 (2022), https://www.epa.gov/system/files/documents/2022-03/fy-2022-2026-epa-strategic-plan.pdf.
[377] *Id.* at 27.
[378] *Id.*
[379] EPA indicates that the proposal "would achieve nationwide reductions in EGU emissions of multiple health-harming air pollutants including nitrogen oxides (NO_x), sulfur dioxide (SO_2), and $PM_{2.5}$. These reductions in health-harming pollution would result in significant public health benefits including avoided premature deaths, reductions in new asthma cases and incidences of asthma symptoms, reductions in hospital admissions and emergency department visits, and reductions in lost work and school days." 88 Fed. Reg. at 33245. EPA also stated that the proposal is "anticipated to lead to modest but widespread reductions in ambient levels of $PM_{2.5}$ for a large majority of the nation's population, as well as reductions in ambient $PM_{2.5}$ exposures that are similar in magnitude across all racial, ethnic, income and linguistic groups. Similarly, the EPA found that the proposed standards are anticipated to lead to modest but widespread reductions in ambient levels of ground-level ozone for the majority of the nation's population, and that in all but one of the years evaluated the proposed standards would lead to reductions in ambient ozone exposures across all demographic groups. Although these reductions in $PM_{2.5}$ and ozone exposures are small relative to baseline levels, and although disparities in $PM_{2.5}$ and ozone exposure would continue to persist following these proposals, the EPA's analysis indicates that the air quality benefits of these proposals would be broadly distributed." Id. See generally, EPA, RIA, ch.4.
[380] The agency's modeling as of the date of proposal—which did not include the proposed limits on existing gas—shows "the proposed rules will lead certain EGUs to decrease emissions, while others increase emissions, in the four snapshot years analyzed...." EPA, RIA, at 6-13. As many as 50 percent of Americans are "predicted to experience worsening ozone concentrations," id. at 6-14, and as many as 25 percent of Americans may experience worsening $PM_{2.5}$ concentrations, under the main proposal. Id., at 6-13 to 6-14. We anticipate that EPA will model air quality impacts again based on the parameters of the final rule.

CCS or deploy greater gas co-firing, compared to just coal combustion.[381] A recent analysis by Resources for the Future indicates that SO_2 reductions of 99 percent are expected at coal plants that retrofit with carbon capture.[382] Carbon capture retrofit projects may also necessitate other additional pretreatment controls for NO_x and/or PM, depending on the particular application and capture technology.[383]

At the same time, certain co-pollutant emissions may increase as a result of meeting the proposed standards. For carbon capture projects, EPA notes that "[s]caling a unit larger to provide heat and power to the CO_2 capture equipment would have the potential to increase non-GHG air emissions."[384] For units that comply via hydrogen co-firing, the agency notes that "[t]he combustion characteristics of hydrogen can lead to localized higher temperatures during the combustion process. These 'hotspots' can increase emissions of the criteria pollutant NOx. NOx emissions resulting from the combustion of high percentage by volume blends of hydrogen are also of concern in many regions of the country."[385]

These potential emissions increases could be larger if existing units that retrofit these technologies operate more than previously as a result of changed economics, including tax credits.

The proposal states that "... most of [such emissions] would be mitigated or adequately controlled by equipment needed to meet other Clean Air Act requirements."[386] It further notes that "most CCS technologies work much more effectively when the EGU is emitting the lowest levels of SO_2 possible; therefore it is likely that as a part of a CCS installation, companies will improve their EGUs' SO_2 control."[387]

But these statements do not assure mitigation of all potential co-pollutant increases, especially NO_x. Additional measures may be necessary. Where EPA has authority and influence, the agency should put in place requirements, and work with states, to evaluate whether any co-pollutants are expected to increase and prevent any increases in co-pollutants. See below for specific actions EPA can take.

B. Cumulative Impacts

Many environmental justice, overburdened, and disadvantaged communities have long experienced extra danger to health and wellbeing because of the cumulative impacts of multiple

[381] 88 Fed. Reg., at 33354 ("SO_2, $PM_{2.5}$, acid gas, mercury and other hazardous air pollutant emissions that result from coal combustion are reduced proportionally to the amount of natural gas consumed, i.e., under this proposal, by 40 percent."); *id.* at 33413 ("most CCS technologies work much more effectively when the EGU is emitting the lowest levels of SO_2 possible; therefore it is likely that as part of a CCS installation, companies will improve their EGUs' SO_2 control."); *see also* Great Plains Institute, *Carbon Capture Co-benefits* (Aug. 2023) [Attachment 6] (analyzing impact of installing CCS on NO_x, SO_2 and PM emissions).
[382] Sanjay Purswani & Daniel Shawhan, *How Clean Is Your Capture: Co-emissions from Planned US Power Plant Carbon Capture Projects* (July 2023), https://media.rff.org/documents/WP_23-29.pdf (RFF Working Paper 23-29).
[383] *See* 88 Fed. Reg. at 33349.
[384] 88 Fed. Reg. at 33302.
[385] 88 Fed. Reg. at 33312.
[386] 88 Fed. Reg. at 33302.
[387] 88 Fed. Reg. at 33413.

pollutants and sources on those communities. This has been the lived experience of environmental justice, overburdened, and disadvantaged communities for decades. Recently, concern for cumulative impacts has been recognized in law in states such as California and New Jersey. EPA itself has embraced the need to protect against cumulative impacts, as recognized in a Cumulative Impacts Research Report[388] last year, and the agency has indicated that a cumulative impacts framework will be forthcoming. President Biden also devoted considerable attention to cumulative impacts in the most recent version of the federal Environmental Justice Executive Order.

At its core, analysis of cumulative impacts captures the full picture of burdens on a community and aims to reduce, or at least not allow increases in, the community's total amount of pollution. Thus, any increase in the total amount of pollution in an already overburdened or vulnerable community should be unacceptable. In California, New Jersey, and similar states, there are now procedures for identifying overburdened or disadvantaged communities, identifying environmental and health stressors and impacts (particularly if they are disproportionate), and most importantly identifying ways to avoid, minimize, and/or reduce contributions to adverse impacts.

In this sense, from the perspective of cumulative impacts, already overburdened communities are not adequately protected by EPA's mention of capturing "most" emissions or that only "adequately" control increased emissions. That still leaves unacceptable risks for communities already overburdened. The proposed rule and accompanying analysis did not include any cumulative impacts information. Without such information, communities cannot see the full picture. We recommend that EPA undertake a cumulative impacts analysis as part of this rulemaking and provide states with information that they can use in mitigating cumulative impacts in implementing the rule.

C. Recommendations for Ensuring Community Protections

We appreciate the proposal's requirements for meaningful community participation and engagement in the state plan process. They are important. However, engagement alone does not ensure community protection. As written, the proposed rule does not require states to conduct and make public sufficient analysis of co-pollutant and cumulative risks for affected communities, nor does it contain substantive protections against increases in co-pollutants.

More rigorous application of the Act's "modification" provisions, as we recommend below, can help limit or prevent such pollutant increases. But even with these reforms, sufficient protections may not be assured.

As we recommend above, EPA should adopt a requirement for cumulative impacts analysis which includes exploration and implementation of ways to avoid, minimize, and/or reduce contributions to adverse impacts. State plans should include considerations for and protections

[388] EPA, Off. Rsch. & Dev., Cumulative Impacts Research: Recommendations for EPA's Office of Research and Development (September 30, 2022), https://www.epa.gov/system/files/documents/2022-09/Cumulative%20Impacts%20Research%20Final%20Report_FINAL-EPA%20600-R-22-014a.pdf.

against local emission spikes in emissions and exposure that would cause disproportionate harm to already overburdened communities.

EPA should make clear that States may take many more factors into account. As noted, adding CCS to the power plants that now pollute the most is expected to significantly reduce SO_2 emissions. But because there is also the potential to increase some other co-pollutants, such as NOx, it is important to evaluate that potential and avoid co-pollutant increases and cumulative impacts. Individual proposed CCS projects that are not properly sited, constructed, and operated or that don't meet other federal, state and local planning, community engagement, and permitting requirements should not go forward.[389]

As just noted, there is a potential for criteria air pollutants such as NO_x and $PM_{2.5}$ to increase in some areas, due to compliance actions taken to meet the rule and increases in generation at some other plants. To mitigate these harms to local air quality and public health, we urge EPA to further evaluate the expected emission reductions and potential emission increases from CCS projects, and to take steps to ensure that any harms to local air quality and public health are prevented. For example, this could include taking steps, within EPA's authority under the Clean Air Act, to:

- Improve application of the statutory "modification" NSPS provision in Section 111(a)(4) and under the Prevention of Significant Deterioration (PSD) and non-attainment New Source Review (NSR) pre-construction permitting programs; and
- Strengthen application of NOx Reasonably Available Control Technology for EGUs in ozone nonattainment areas.

EPA has ample authority to prevent emission increases in co-pollutants associated with installation of control equipment. While the overall level of co-pollutants will fall, this important GHG rule has the potential to result in emission increases at units that install control equipment. EPA should take this opportunity to review its implementation of the Clean Air Act's modification provisions under the NSPS, PSD, and NSR programs to assure that sources with actual emission increases are subject to the requirements of these protective statutory programs.

X. State Plans

Commenters generally support EPA's approach to State Plans and emphasize the need for Plans to maintain the stringency of EPA's BSER and timely achieve the requisite emission reductions while accounting for states' differing administrative processes and need for a certain amount of compliance flexibility. Commenters incorporate by reference the attached joint comments on EPA's proposed revisions to the Section 111(d) implementing regulations, filed February 27, 2023 (EPA-HQ-OAR-2021-0527-0099), and add below specific comments on additional issues raised in this proposal.[390]

[389] NRDC emphasizes that all sequestration projects should include strong bonding requirements and no liability limitations.
[390] Comments of CATF et al. on Proposed Rule: Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d), Docket ID No. EPA-HQ-OAR-2021-0527-0099 (Feb. 27, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0527-0099.

A. Requirement for State Plans To Maintain Stringency of EPA's BSER Determination

The proposed emission guideline regulation provides a clear framework for each state to write its state plan. The core requirement of an approvable state plan is establishing the standard of performance applicable to each covered EGU within the state. The simplest pathway is for a state to calculate the numerical emission rate applicable to each source through the formula EPA has provided—in other words, to calculate each source's baseline emission rate, apply EPA's percentage reduction for the relevant subcategory, and determine the source's enforceable emission rate. The proposal permits a state to set a different emission rate limit for a source if the state demonstrates, through consideration of the source's RULOF, that the source has certain fundamentally different characteristics than the other sources in the subcategory to which it was assigned. And finally, the proposal allows states to submit a plan that the state demonstrates will achieve at least equivalent emission reductions as compared to a plan following the unit-by-unit pathway just described.

This approach comports with the Supreme Court's description of Section 111(d) in *West Virginia v. EPA*, namely: that EPA has "the primary regulatory role in Section 111(d)."[391] "The Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. It does so by again determining, as when setting the new source rules, 'the best system of emission reduction ... that has been adequately demonstrated for [existing covered] facilities.'.… The States then submit plans containing the emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA."[392]

We support EPA's proposal to require that state plans include emission limitations for each source that achieve equivalent emission reduction stringency to EPA's BSER determination. We agree that this requirement flows directly from the purpose and structure of the Clean Air Act. Section 111(d) contemplates a cooperative federalism structure "similar to [the procedure] provided by section 110," in which states devise plans to meet certain statutory objectives.[393] As with state implementation plans submitted pursuant to Section 110, EPA must ensure that state plans under Section 111 satisfactorily meet the minimum requirements set forth in the Clean Air Act. In enacting the 1970 Clean Air Act Amendments, Congress prescribed "a drastic remedy to what was perceived as a serious and otherwise uncheckable problem of air pollution… plac[ing] the primary responsibility for formulating pollution control strategies on the States, but nonetheless subject[ing] the States to strict minimum compliance requirements."[394] EPA's determination of the degree of emission limitation achievable under its BSER is just that: a minimum compliance requirement that state plans must reflect.

391 *West Virginia v. EPA*, 142 S. Ct. 2587, 2601 (2022).
392 *Id.* at 2601-2602.
393 *Id.* at 2630 (citing 42 U.S.C. § 7411(d)(1)).
394 *Union Elec. Co. v. EPA*, 427 U.S. 246, 256-257 (1976).

B. Establishing State Standards of Performance

1. Establishing Baseline Emission Performance

The proposal sets forth EPA's determination of the BSER for each subcategory of EGUs, and the percentage reduction in baseline CO_2 emissions that EPA has determined is achievable by sources in the subcategory. For example, the emission guideline specified for existing coal-fired units operating in 2040 or beyond is an 88 percent reduction from the source's baseline, reflecting the capabilities of CCS. A different percentage reduction is specified for each subcategory of sources and its associated best system.

The initial task for each state is to apply the EPA guideline to determine a standard of performance for each source. The steps each state must follow are to determine (1) the baseline emission rate for each covered EGU in the state and (2) the standard of performance for each source, in lbs/MWh, by applying the relevant percentage reduction to the source's baseline value. This results in an individualized standard of performance for each such source. EPA has proposed that the state determine the baseline for each unit by calculating the average emission rate of the unit over an eight consecutive quarter period picked from within the last five years.

Commenters generally support this approach while encouraging EPA to include certain additional requirements to make sure that the basis for these calculations is standardized, transparent, and easily reviewed by the states themselves, by EPA, and by members of the public. There are dozens of affected units in many states, and hundreds across the nation. What is needed is an electronic form or worksheet, standardized across the states, for each operator and each state to show the basis of the source-specific calculations. The form or worksheet for each unit should display at least the following information:

- Name and identifiers for each unit (these presumably already exist for other reporting purposes);
- Identification of the relevant subcategory;
- Identification of the eight-quarter baseline period chosen for the unit (with supporting data appended in a standardized way);
- The average CO_2 emissions per MWh for that period (with supporting data appended in a standardized way); and
- The emission rate determined to be the standard of performance for that source, applying the relevant percentage reduction.

This source-specific information should be incorporated by each state into its plan, made public on a website maintained by each state, and submitted to EPA electronically in a standardized format and compiled on an EPA website.

If the state proposes a different standard pursuant to consideration of RULOF, the supporting information for its fundamentally different factors determinations should also be presented step-by-step in this standardized unit-specific form. We further address RULOF below.

2. RULOF Variance Considerations

Commenters generally support EPA's proposed provisions related to consideration of RULOF. As provided in EPA's proposed revision of the implementing regulations for Section 111(d), EPA is making clear that variances from the emission guidelines are intended only for cases where the state demonstrates that the circumstances of a particular source are fundamentally different from those EPA assessed in establishing the applicable standard for the subcategory to which the source belongs.

Commenters note at the outset that the structure of this emission guideline goes a long way to accommodate circumstances that might otherwise give rise to variance requests. For starters, as described above, each source will have an individualized emission limitation derived from its own baseline emission rate. That structure accounts for substantial variation that may exist among sources in the same subcategory.

Commenters support an additional limitation that EPA proposed for this rule. As the proposal explains, EPA has already considered affected coal steam generating units' RULOF in determining the subcategories and the appropriate emission limitations for them. Coal units intended to run in 2040 and beyond, for example, are in a different subcategory from units with different operating horizons. The emission guideline for each source is dependent on the subcategory to which its operator and the state assign it. The operator and the state have flexibility to choose the appropriate subcategory and standard for each source based on clearly defined ranges of operating horizon. For these reasons, EPA states that it does not anticipate a state invoking RULOF based on a coal-fired unit's operating horizon. Commenters agree that to allow that would be to double-count RULOF as a relevant factor.

Commenters also support EPA's position that cost differences must be fundamental to justify granting a RULOF variance. A small difference in costs compared to the norm or average in a subcategory is not sufficient. Congress decided EPA and the states should regulate by category under Section 111, and a category approach groups sources that are similar, not only sources that are the same. Thus, some variation in costs of compliance are inherent in such an approach. For this reason, EPA is correct to require that an individual source must exhibit fundamental cost differences from the norm in the subcategory in order to merit a variance.

We anticipate that other commenters will suggest that RULOF variances be available for such factors as distance to a CCS disposal site or distance to a hydrogen source. Claims that resources are too distant must be evaluated in economic terms: is the disposal or fuel transportation cost for a given source demonstrated to be outside the range for its subcategory peers, and is that difference large enough to be considered fundamental? Minor or modest differences within the range of other sources within the same subcategory should not be considered fundamental.

In addition, Commenters support EPA's proposed requirement for States to document health or environmental impacts and benefits associated with control options when conducting source-specific BSER analyses. For example, if a State's comparison of BSER options indicates emissions from an affected unit could be controlled at a higher cost and that such control would benefit communities who would otherwise be adversely impacted by the less stringent control option, a State could conclude the higher cost option is warranted for the specific source.

3. Increments of Progress and Milestones for Affected EGUs

Commenters support EPA's proposed emission guideline-specific increments of progress toward compliance with the standards using BSER control options, and the federally enforceable milestones for units electing to permanently cease or limit operations by a certain date to qualify for a less stringent BSER. Such increments and milestones help ensure interim accountability, timely compliance, and fair notice to communities regarding timing of essential steps toward compliance. Commenters recognize that such increments and milestones should be implementable and therefore be able to account for minor, unavoidable changes to the interim targets.

Some industry commenters may express concern that there may be unexpected impediments to timely compliance that are out of their control, e.g., delays in completing pipelines to carry off CO_2 or to deliver gas or hydrogen. For some contingencies, an owner/operator should be expected to build into contracts with vendors or other suppliers provisions to discourage non-performance or delays. There are, however, at least two practical means of accommodating genuine occurrences that are out of the owner/operator's control. For minor delays, states and EPA can exercise enforcement discretion through appropriate administrative channels (e.g. ACOs); if the delay is short there is no practical exposure to citizen enforcement suits, which take considerable time. For longer delays that are likely to impact the ultimate BSER compliance schedule or performance standard, then a State should utilize the RULOF process to account for such changes. An owner/operator can apply for, and a state can issue, a RULOF variance as an amendment to the original state plan. Like any other RULOF variance issued after state plan approval, the variance would be a state plan amendment subject to review by EPA to assure that the plan remains satisfactory. The need for EPA review should not be an obstacle if the circumstances are a short delay occasioned by a matter truly outside the owner/operator's control.

C. Compliance Flexibilities

We support EPA's proposal to allow states to incorporate averaging and emission trading into their plans, as long as the state demonstrates, and EPA concurs upon review, that such mechanisms result in emission reductions at least equivalent to those achieved by each source individually meeting its standard of performance. To make this showing, a state would need to submit an analysis of the emissions resulting from applying the emission guideline to each individual source as per the basic rule, and then show that the total pollution with averaging or trading will be no higher than that. The state should also be required to demonstrate that the averaging or trading program provides air pollution reduction benefits in disproportionately impacted communities that are equivalent to or better than the air pollution reduction benefits that would otherwise be achieved through source-level compliance with the standards.

An equivalence demonstration will be relatively straightforward in the case of averaging between co-located sources, whereas ensuring equivalent emission performance in the aggregate will be more difficult for emission trading programs that cover sources statewide or across a multi-state area. As discussed in the proposal, there are many considerations that must be evaluated and addressed for any averaging or trading program under these emission guidelines. Therefore, it will be best to address averaging and trading on a state-by-state basis at the plan approval stage for any state that wants to utilize one of these compliance flexibility options.

It is also important to emphasize that the subcategories proposed under these emission guidelines for steam generating units already provide for much of the operational flexibility that would be provided through trading. Many sources whose BSER is based simply on routine methods of operation and maintenance may record emission rate levels well below the undemanding emission rates required of them. This includes imminent-term and near-term coal-fired steam generating units and gas- and oil-fired steam generating units. It would not be appropriate for these sources to generate averaging or trading credits to allow a more rigorously regulated source to exceed its otherwise applicable limit. Similarly, EPA should not allow a source with a RULOF variance to generate credits or to comply with its RULOF standard of performance through trading.

For other sources and subcategories, averaging and trading programs (with compliance instruments denominated in one ton of CO_2) can provide important operational flexibility and reduce costs that may otherwise be borne by ratepayers. Where averaging is utilized for affected EGUs at the same plant level, compliance demonstrations should be straightforward and not pose any serious concerns. However, once a state moves to establish a trading program where compliance instruments are generated and transferred between units or plants at separate sites, things get much more complex. States will need to certify compliance instruments, establish a tracking system through which compliance instruments are traded and retired, and have adequate enforcement. These tracking and enforcement issues become even more complicated for programs that allow trading among sources in different states.

The potential benefits of trading programs under these emission guidelines must be weighed against these complexities, and EPA should encourage states to carefully consider these factors before they decide to establish a trading program. Also, we emphasize the need for EPA to apply stringent criteria to ensure the integrity of any trading programs when the Agency takes action to review and approve state plans.

D. State Plan Components and Submission

The Commenters generally support EPA's proposed requirements for the contents of State plans, the proposed timing of such plans, and EPA's plan for review and action on the plans, including applicability of Federal plans. We urge EPA, however, to provide a strong foundation for transparent communications and robust collaborations, implement efficient regulatory mechanisms, and exigently execute federal planning in the absence of state action.

1. EPA Should Engage In and Support Transparent Communications to Ensure Timely, Approvable State Plans

Although states are certainly capable of developing appropriate State plans, they will likely look to EPA for guidance during the development process, especially around source applicability, meaningful community engagement, and plan approvability. EPA could greatly aid states' planning by ensuring EPA regional offices are prepared and well-resourced to assist states upon rule finalization and are willing to provide timely feedback on whether a State's plan is on track for approval. There may be additional guidance or tools states request to assist with plan development or implementation that EPA should consider to help ensure timely, approvable State plans and efficient implementation (e.g., model permit or other regulatory language).

2. EPA Should Employ Regulatory Mechanisms That Enhance State Planning Efficiency and Swiftly Act to Implement a Federal Plan Where State Planning Falls Short

If EPA's proposed subpart Ba revisions are finalized, the agency would have additional regulatory mechanisms at its disposal to streamline the state plan review process, accommodate different state processes, facilitate cooperative federalism, and further protect public health and welfare. Commenters generally support the proposed use of the regulatory mechanisms designed to enhance efficiency and align the Section 111(d) program with similar procedures available under Section 110, which provide flexibility for states and EPA to ensure emission reductions are appropriate and timely.

Under EPA's proposed emission guidelines, certain administrative completeness criteria for State plans would require evidence of final adoption of the plan, regulations, relevant permits, orders, or agreements. While these are of course critical elements to the State plan, varying state administrative processes may require longer timelines to achieve final form or adoption. This should not, however, require additional time beyond EPA's proposed 24-month time clock for states to submit Plans or preclude EPA from reviewing an essentially complete State plan under the agency's proposed parallel processing mechanism. EPA has proposed guardrails for implementing this process in the agency's Subpart Ba revisions; as such, this could be a useful mechanism for ensuring appropriate federal oversight while recognizing unique state administrative processes. In addition, the proposed regulatory mechanisms providing for partial or conditional approval or partial disapproval of state plans could provide additional flexibility and certainty while clearly identifying and requiring specific measures, within specific timeframes, for State plan completion and approvability. Where state planning falls short, EPA should swiftly implement federal plans to ensure the public health, safety, and welfare is protected.

E. Meaningful Stakeholder and Community Engagement

As referenced in the earlier section on co-pollutants, cumulative impacts, and community protections, meaningful community engagement will be an important part of the state planning process. EPA can encourage best practices for meaningful community engagement that ensure adequate opportunities for public involvement in decision-making, and should draw from existing recommendations and resources from state agencies[395] as well as non-governmental

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[395] *See, e.g.,* State of Oregon Env't Justice Task Force, *Best Practices for Oregon's Natural Resource Agencies* 5-6, 16-19 (2016), https://www.oregon.gov/odot/Business/OCR/Documents/Oregon_EJTF_Handbook_Final.pdf; Colo. Environmental Justice Action Task Force, Final Report of Recommendations 33-44 (Nov. 14, 2022), https://drive.google.com/file/d/1l4rN-o3h3OJg8TciUzh-qxytULvyD_NE/view; Wash. State Env't Justice Task Force, *Recommendations for Prioritizing EJ in Washington State Government* 64-68, Appendix C (2020), https://healthequity.wa.gov/sites/default/files/2022-01/EJTF%20Report_FINAL%281%29.pdf; Minn. Pollution Control Agency, *Environmental Justice Framework* 9 (May 2022), https://www.pca.state.mn.us/sites/default/files/p-gen5-05.pdf; Cal. Air Resources Bd., *Community Engagement Model* (2023), https://ww2.arb.ca.gov/community-engagement-model.

entities, scholars, environmental justice leaders, and community groups.[396] These resources include common themes of:

- gathering data and conducting analysis, including cumulative impacts analysis, to be able to answer the question of who is being impacted and how;
- making forums well-advertised and accessible be it language, location, time, assistance, with the support of a trusted partner as well as interactive, early, and ongoing;
- allowing multiple forms of input from emails to comment portals to in-person or virtual meetings and a way to reflect back the comments that have been received; and
- sharing of information, timeline, milestones, etc., in a timely and transparent manner.

The essential and ultimate achievement in stakeholder and community engagement is being able to demonstrate how community comments and concerns are reflected into the decisions made. This is important not only for its substantive value, but also for its ability to build trust and integrity in the community engagement process. The more meaningful and robust the stakeholder and community engagement, the better informed and protective compliance will be.

XI. EPA Properly Proposes to Repeal the ACE Rule Which is Out-of-Date, Was Not Based on the Best System and Contained No Emission Limitations

Commenters support EPA's proposal to repeal the so-called "Affordable Clean Energy Rule" (ACE). Commenters argued that ACE was illegal at the time it was proposed and thereafter, and maintain that position today. The ACE Rule was impermissibly toothless and weak when finalized and is also now well out of date. The rule imposed no limits on CO_2 from gas-fired power plants, which comprise the largest share of power generation. The minimal (under 1 percent) emission reduction ACE anticipated from coal-fired plants has already been exceeded without ACE going into effect.

EPA proposes to repeal ACE based on the following three reasons: 1) heat rate improvements (HRI) are not the BSER for existing coal-fired power plants; 2) the reasons the agency rejected CCS and natural gas co-firing no longer apply; and 3) ACE conflicted with Clean Air Act

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[396] *See, e.g.*, Int'l Ass'n for Pub. Participation, *Public Participation Pillars*, https://cdn.ymaws.com/www.iap2.org/resource/resmgr/communications/11x17_p2_pillars_brochure_20.pdf (last visited Aug. 7, 2023); WE ACT for Env't Justice, *Community Engagement Brief* (2022), https://www.weact.org/wp-content/uploads/2022/10/Community-Engagement-Brief-092322-FINAL.pdf; PolicyLink & The Kirwan Institute, *The Community Engagement Guide for Sustainable Communities* (N.D.), https://www.policylink.org/sites/default/files/COMMUNITYENGAGEMENTGUIDE_LY_FINAL%20%281%29.pdf; Gov't Alliance on Race and Equity, *Racial Equity Toolkit* (2016), https://www.racialequityalliance.org/wp-content/uploads/2015/10/GARE-Racial_Equity_Toolkit.pdf ; Tribal Collaboration Working Group of the All of Us Research Program Advisory Panel, *Considerations for Meaningful Collaboration with Tribal Populations* (2018), https://allofus.nih.gov/sites/default/files/tribal_collab_work_group_rept.pdf; Facilitating Power, *The Spectrum of Community Engagement to Ownership* (2021), https://movementstrategy.org/wp-content/uploads/2021/08/The-Spectrum-of-Community-Engagement-to-Ownership.pdf .

Section 111 and the implementing regulations because it did not specifically identify the BSER or associated emission limit.[397]

Commenters agree that ACE must be repealed and we expand upon and strengthen the three rationales below.

First, EPA is correct that HRI alone are not the BSER for coal-fired power plants. Review of ACE modeling demonstrates that a rule based solely on HRI could have resulted in greater use of coal plants and *more* emissions from coal plants overall.[398] As Commenters explained at the time, HRI can result in increased emissions from individual plants and the source category overall.[399] Improving the efficiency of a coal-fired power plant will in many instances cause a plant to increase its generating output and, even more importantly, the investment in the plant may cause it to extend its useful life and continue polluting.[400] Moreover, new analysis EPA includes in the docket associated with this proposal from Sargent & Lundy indicates that HRI measures are even less effective at reducing CO_2 emissions than assumed in 2019.[401]

Second, as Commenters explained then, EPA inappropriately rejected CCS and gas co-firing when ACE was finalized. Therefore, intervening changes only make CCS and gas co-firing an even more reasonable basis of standards now than they were in 2019. The reasons EPA sets forth in this proposal include that there are fewer coal-fired power plants and therefore fewer infrastructure needs associated with the system, greater supply of natural gas to support gas co-firing and reduced cost for CCS and gas co-firing technologies. As discussed above, in the intervening years costs for CCS, especially, have declined through deployment and technological learnings as well as the expanded 45Q tax credit and the technology can eliminate nearly all climate pollution from a fossil fuel-fired power plant making it a far superior pollution control to HRI.

Finally, the ACE rule's emission guideline regulation did not include *any* quantitative emission limitation, but merely sketched out procedural steps for states with no meaningful measure of what emissions performance was required in a "satisfactory" state plan. As the Supreme Court confirmed in *West Virginia*, "EPA itself [has] the primary regulatory role in Section 111(d). The Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved."[402] EPA must choose the BSER and an emission limit that reflects application of the system.[403] "The States then submit plans containing the emission restrictions that they intend to adopt and enforce in order to not exceed the permissible level of pollution established by

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[397] 88 Fed. Reg. 33335-36.
[398] Comments of CATF et al. on Proposed Rule: Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program, Docket ID no. EPA-HQ-OAR-2017-0355-23806, at 14-17 (Oct. 31, 2018), https://www.regulations.gov/comment/EPA-HQ-OAR-2017-0355-23806.
[399] *Id*. at 17-42.
[400] *Id*.
[401] Sargent & Lundy, *Heat Rate Improvement Method Costs and Limitations Memo*, Docket ID No. EPA-HQ-OAR-2023-0072-0018 (2023), https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0018.
[402] *West Virginia v. EPA*, 142 S.Ct. 2587, 2601-02 (2022).
[403] 42 U.S.C. § 7411(a)(1).

EPA."[404] In the ACE Rule, EPA failed to adopt a BSER or set a binding emission limit for state plans. EPA must repeal the ineffective and illegal ACE Rule.

Conclusion

EPA's proposed rule provides a thoughtful and meaningful framework to ensure that fossil fuel-fired power plants are well controlled for their carbon pollution, with emission limits that reflect the capabilities of demonstrated and cost-reasonable traditional pollution controls, while maintaining reliability and flexibility. The proposal follows the regulatory pathway set forth in *West Virginia v. EPA* and reinforced by Congress in the IRA. The proposal properly builds on ongoing trends in the power sector and the emissions trajectory driven by the incentives Congress itself provided. It provides lengthy lead times for accomplishing necessary reductions. These comments provide additional evidence for the record to support and strengthen the final rule and better serve the purposes of the Clean Air Act. As the climate crisis deepens, we look forward to continued work with EPA to strengthen and finalize these crucial standards to protect the health of Americans and the world we inhabit.

Respectfully Submitted,

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[404] *West Virginia*, 142 S. Ct. at 2602.

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List of Attachments (Commenters' Analyses and Commissioned Reports)

Attachment No.	Source
[1]	David Doniger, West Virginia*, the Inflation Reduction Act, and the Future of Climate Policy*, 53 Env't L. Rep. 10553 (2023), https://www.eli.org/sites/default/files/files-pdf/Doniger%20Feature%20July%202023.pdf
[2]	Metin Celebi et al., *A Review of Coal-Fired Electricity Generation in the U.S.* 3 (2023), https://www.brattle.com/wp-content/uploads/2023/04/A-Review-of-Coal-Fired-Electricity-Generation-in-the-U.S..pdf
[3]	ERM, *Model Comparisons for Potential Impacts of the IRA on the U.S. Power Sector* (2023)
[4]	ERM, *Review of Projections through 2040 of U.S. Clean Hydrogen Production, Infrastructure, and Costs* (2023)
[5]	Andover Technology Partners, *Natural Gas Cofiring for Coal-Fired Utility Boilers* (2022)
[6]	Great Plains Institute, *Carbon Capture Co-benefits* (Aug. 2023)
[7]	Wood Group, *CCS Technology Transfer Assessment Report* (2023)
[8]	Carbon Solutions, LLC, Clean Air Task Force: Final Report (Sept. 21, 2022)
[9]	Carbon Solutions, LLC, *Oceankind: CCS Potential in the US Mid-Atlantic using Offshore Storage* (May 19, 2023)
[10]	CATF, *U.S. Carbon Capture Activity Tracker*
[11]	Carbon Solutions, LLC, *National Assessment of Natural Gas Combined Cycle (NGCC) and Coal-fired Power Plants with CO_2 Capture and Storage (CCS)* (Sept. 2022)
[12]	Carbon Solutions, LLC, *Affected Fleet Sensitivity* (2023)
[13]	Norm Schilling, *Emissions and Performance Implications of Hydrogen Fuel in Heavy Duty Gas Turbines* (2023), https://cdn.catf.us/wp-content/uploads/2023/07/20174030/emissions-performance-implications-hydrogen-fuel-heavy-duty-gas-turbines.pdf
[14]	Battelle Memorial Institute, *Independent Assessment of State of the Art for Carbon Capture and Sequestration for Fossil Powered Electricity Generation* (Mar. 2023)

Appendix A – Carbon Capture and Sequestration

Fossil fuel-fired power plants can be built and retrofitted with carbon capture and storage and, when controlled in that way, can play a valuable role in a decarbonized grid by providing clean firm power when required and acting as flexible, low-carbon backup to renewable generation. The technology is adequately demonstrated and cost reasonable for new and existing coal- and gas-fired power plants. The U.S. has been active in developing a favorable economic landscape for CCS deployment, including through the funding of demonstration projects and transport and storage infrastructure for CO_2 as well as by establishing an economic incentive through the 45Q tax credit.[405] This appendix surveys the existing state of CCS technology and its qualities as they relate to its role in mitigating power sector emissions.

I. Post Combustion Capture Is Adequately Demonstrated

A long history of experience, in the United States and around the world, demonstrates the feasibility of post combustion carbon capture technology on power plants. In addition to the several examples of existing deployment of capture technology at power plants, a wealth of knowledge—from permit and application reviews, FEED studies, vendor-provided information, and deployment of the technology in other industries—developed over many years reinforces the technology's readiness.[406]

A. Existing Deployment of Carbon Capture at Power Plants

For many years and at many sites, carbon capture technology has been applied on power plants and similar flue gas streams. Demand for CO_2 from sectors such as the food and beverage industry drove the development of many smaller-scale, post-combustion capture plants from the early 1980s, including coal-, gas-, and oil-fired boilers and furnaces, gas engines and gas turbines.[407] These range in scale from around 100,000 to 500,000 tons of CO_2 per year, and separate CO_2 from gas mixtures of very similar composition to full-scale power plants, usually using amine solvent-based technologies supplied by companies including Fluor, MHI and ABB Lummus.[408]

For example, since 1978, up to 270,000 tons per year of CO_2 have been captured from a captive coal power plant operated by Searles Valley Minerals in California for use in the production of

[405] Material for this appendix has been sourced from Comments of CATF in response to Draft White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units, Docket ID No. EPA-HQ-OAR-2022-0289 (June 6, 2022) [hereinafter CATF, *White Paper Comments*], https://www.regulations.gov/comment/EPA-HQ-OAR-2022-0289-0029.
[406] For a fuller accounting of major CCS projects in operation or under development, see Jay Duffy & John Thompson, *The Time is Now: The Biden Administration Must Adopt Strict CO_2 Standards for the Power Sector*, CATF (Feb. 7, 2023), https://www.catf.us/2023/02/time-now-biden-administration-must-adopt-strict-co2-emission-standards-power-sector/.
[407] *Commercially Available CO_2 Capture Technology*, Power (Aug. 1, 2009), https://www.powermag.com/commercially-available-co2-capture-technology/.
[408] Int'l Energy Agency (IEA) GHG R&D Programme (IEAGHG), *Improvement in power generation with post-combustion capture of CO_2* (2004), https://ieaghg.org/docs/General_Docs/Reports/PH4-33%20post%20combustion.pdf. *See* Table 1 *infra*.

soda ash. Two AES-owned coal power plants capture industrial quantities of CO_2 from flue gas slipstreams for use in the food and beverage industry and dry ice, using ABB Lummus capture technology: 66,000 tons per year are captured at Shady Point, OK, while 45,000 tons per year are captured from the 180 MW Warrior Run, MD.

Using these existing technologies, modified variants, or entirely new solvents, more large-scale trials on coal power plant flue gas were carried out from the 1990s, now with climate mitigation as the primary motivation. In 2014, this culminated in the first full-scale demonstration of CO_2 capture processing all of a coal power plant's flue gas output, with the 1 million metric ton per year scale plant at Boundary Dam 3 in Canada using Shell Cansolv technology. Although this plant encountered initial operational issues associated with excessive entry of flue gas contaminants into the solvent system, correctional measures and modifications have led to steady improvements in availability and performance, with 94 percent capture plant availability from 2017 to 2019 and over 857,000 metric tons captured in fiscal year 2022 to 2023.[409]

In 2011,[410] MHI used their experience with capture on natural gas-fired boilers to demonstrate capture on coal at Southern Company's Plant Barry[411] in Alabama on a 25 MW slipstream. Success at Plant Barry enabled MHI to apply carbon capture at a much larger scale at the Petra Nova project on the WA Parish plant (a 240 MW-equivalent slipstream).[412] Petra Nova operated successfully from January 2017 to September 2020, when it suspended operation due to falling oil prices that impacted a business model reliant on enhanced oil recovery. Over these three years, the project captured 83 percent of the planned volume of CO_2, but with a steady increase from 72 percent in 2017 to 95 percent in 2019, as technical issues (many similar to those encountered at Boundary Dam) were addressed.[413] Outages of the CO_2 capture unit were responsible for only 28 percent of unplanned outages. The Petra Nova CCS plant is expected to restart in August 2023.[414]

Likewise, Fluor developed a carbon capture project at the Bellingham NGCC plant in Massachusetts from 1991 to 2005 capturing 85 to 95 percent of CO_2 from a 40 MW

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409 Brent Jacobs et al., *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities* (2022), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430; *BD3 Status Update: Q1 2023*, SaskPower (Apr. 20, 2023), https://www.saskpower.com/about-us/our-company/blog/2023/bd3-status-update-q1-2023

410 Material sourced from Duffy & Thompson, *supra* note 406.

411 Mass. Inst. Tech., Carbon Capture and Sequestration Technologies Program, *Plant Barry Fact Sheet: Carbon Dioxide Capture and Storage Project*, https://sequestration.mit.edu/tools/projects/plant_barry.html (last visited Aug. 6, 2023).

412 DOE, Off. Fossil Energy & Carbon Mgmt. (OFECM), *Petra Nova - W.A. Parish Project*, https://www.energy.gov/fecm/petra-nova-wa-parish-project (last visited Aug. 6, 2023).

413 Petra Nova, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report* (2020), https://www.osti.gov/servlets/purl/1608572.

414 Timothy Gardner, *Restart delayed at Texas coal unit linked to Petra Nova CCS project*, Reuters (Aug. 2, 2023), https://www.reuters.com/business/energy/restart-delayed-texas-coal-unit-linked-petra-nova-ccs-project-2023-08-01/.

slipstream.[415] They used this experience to design a coal-fired power plant capture pilot in Wilhelmshaven, Germany, that operated in 2012.[416]

While early large-scale demonstrations of CO_2 capture from coal power have encountered periods of low availability—particularly immediately following commissioning—the capture processes themselves have consistently removed CO_2 from the flue gas they treat at their design rate or above. On average, the capture unit at Petra Nova removed 90.2 percent of CO_2 in the flue gas it processed, while the Boundary Dam 3 capture unit has averaged 89 percent. Lessons in the operational and design modifications required to improve the availability of these units have been incorporated into currently planned projects.[417] Equally, these coal power plant experiences are now being transferred back to natural gas-fired combined cycle plants, generally using the same family of solvents to capture carbon dioxide with minor changes to account for differences in flue gas composition.[418]

Table 1 illustrates the wealth of commercial reference plants that have applied CO_2 capture to post-combustion flue gas streams from power plants, smaller combustion sources, and similar flue gas compositions in industry, such as steam reformer flue gas.

Table 1. Significant solvent-based post-combustion CO_2 capture projects on power plants, industrial furnaces and other combustion sources[419]

Vendor	Location	Exhaust Stream	CO_2 Use
ABB	Searles Valley, CA	Coal Boiler	Chemicals Industry

415 DOE, *Carbon Capture Opportunities for Natural Gas Fired Power Systems*, https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems (last visited Aug. 6, 2023).
416 Univ. Edinburgh, *Wilhelmshaven Pilot Plant: Project Details*, https://www.geos.ed.ac.uk/sccs/project-info/1323# (last visited Aug. 3, 2023).
417 Similarly, early flue gas SO_2 scrubbers had poor initial performance but EPA nonetheless concluded they were adequately demonstrated as a basis for the 1971 NSPS, a conclusion that was upheld by the courts. *See Essex Chem. Corp.*, 486 F.2d at 440.
418 Wood Group, *CCS Technology Transfer Assessment Report* (2023) [hereinafter *Wood Report*] [Attachment 7].
419 Table developed by CATF in preparing Comments of CATF & NRDC in Response to Proposed Rule: Emissions Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emissions Guidelines Implementing Regulations; Revision to New Source Review Program, Docket ID No. EPA-HQ-OAR-2017-0355-24266 (Oct. 31, 2018), https://www.regulations.gov/comment/EPA-HQ-OAR-2017-0355-24266 (several sources' links have since broken). MHI describes these as "post-combustion" capture projects, and the exhaust gas from which the CO_2 is separated is quite similar to conventional combustion gases (68 percent nitrogen, 8 percent CO_2, balance mostly water). Licensing of the PCC technology developed by Kerr-McGee was transferred to ABB in 1990. Howard Herzog, *The Economics of CO_2 Separation and Capture*, at tbl.1, n.1 (N.D.), https://sequestration.mit.edu/pdf/economics_in_technology.pdf. Unless otherwise indicated, information on the MHI projects listed here are from MHI, *Update of MHI CO_2 Capture Technology* (2021), https://www.globalccsinstitute.com/wp-content/uploads/2021/10/1-6_P1_S6_MHIE_Takashi-Kamijo.pdf; Fluor presents several projects here: Fluor, Brochure, Econamine FG Plus, https://www.fluor.com/sitecollectiondocuments/qr/econamine-fg-plus-brochure.pdf.

ABB	Warrior Run, MD	Coal Boiler	Food Industry
ABB	Shady Point, OK	Coal Boiler	Food Industry
TPRI	Shanghai, PRC	Coal Boiler	Food Industry
TPRI	Beijing, PRC	Coal Boiler	Demonstration, Food
MHI	Kedah Darul Aman, Malaysia	NG fired steam reformer (SR) flue gas	Urea production
MHI	Aonla, India	NG fired SR flue gas	Urea Production
MHI	Phulpur, India	NG fired SR flue gas	Urea Production
MHI	Kakinada, India	NG fired SR flue gas	Urea Production
MHI	Vijaipur, India	NG fired SR flue gas	Urea Production
MHI	Bahrain	NG fired SR flue gas	Urea Production
MHI	Phu My, Vietnam	NG fired SR flue gas	Urea Production
MHI	Fukuoka, Japan	NG fired SR flue gas	General use
MHI	Abu Dhabi, UAE	NG fired SR flue gas	Urea Production
MHI	District Ghotoki, Pakistan	NG fired SR flue gas	Urea Production
MHI	Kedah Darul Aman, Malaysia	NG fired SR flue gas	Urea production
MHI	Plant Barry, AL	Coal Boiler	Demo (amine)
Fluor	Bellingham, MA	Gas Turbine Exhaust	Food Industry

Fluor	Lubbock, TX	Natural Gas	Enhanced Oil Recovery
Fluor	Carlsbad, NM	Natural Gas	Enhanced Oil Recovery
Fluor	Santa Domingo, DR	Light Fuel Oil	Enhanced Oil Recovery
Fluor	Barranquilla, Columbia	Natural Gas	Food Industry
Fluor	Quito, Ecuador	Light Fuel Oil	Food Industry
Fluor	Brazil	NG / Heavy Fuel Oil	Food Industry
Fluor	Rio de Janeiro, Brazil	Steam Reformer	Methanol Production
Fluor	Sao Paulo, Brazil	Gas Engine Exhaust	Food Production
Fluor	Argentina	Steam Reformer	Urea Plant Feed
Fluor	Spain	Gas Engine Exhaust	Food Industry
Fluor	Barcelona, Spain	Gas Engine Exhaust	Food Industry
Fluor	Bithor County, Romania	Heavy Fuel Oil	Food Industry
Fluor	Cairo, Egypt	Light Fuel Oil	Food Industry
Fluor	Israel	Heavy Oil Boiler	Food Industry
Fluor	Uttar Pradesh, India	NG Reformer Furnace	Urea Plant Feed
Fluor	Sechuan Province, PRC	NG Reformer Furnace	Urea Plant Feed
Fluor	Singapore	Steam Reformer	Food Industry

Fluor	San Fernando, Philippines	Light Fuel Oil	Food Industry
Fluor	Manila, Philippines	Light Fuel Oil	Food Industry
Fluor	Osaka, Japan	LPG	Demo Plant
Fluor	Chibu, Japan	Refinery Gas Mixture Heavy Fuel Industry	Food Industry
Fluor	Yokosuka, Japan	Coal/Heavy Fuel Oil	Demo Plant
Fluor	Botany Australia	Natural Gas	Food Industry
Fluor	Alton, Australia	Natural Gas	Food Industry
Alstom	New Haven, WV	Coal Boiler	Demo (ammonia)
Alstom	Mongstad, Norway	NG turbine/refinery	Demo (ammonia)
Aker	Mongstad, Norway	NG turbine/refinery	Demo (amine)

EPA has already found that carbon capture is adequately demonstrated, relying on CCS as the basis of its 2015 performance standards for new coal-fired plants. As outlined above, CCS has been successfully deployed on coal-fired power plants, and while it is yet to be deployed on a large-scale gas turbine, this has been due to the lack of a regulatory driver or suitable incentives, rather than any limitations of current technologies.[420] There is nothing fundamentally different about applying the capture technology already used to the emissions of large gas-fired plants.[421] Both EPA (in setting the 2015 NSPS) and suppliers (e.g. MHI, in designing the capture equipment used at Plant Barry) have relied on past experience with capturing emissions from gas-fired boilers and turbines. There are now a wide range of commercial capture solvent technologies available that have undergone years of testing on diverse CO_2 sources.

B. FEED Studies

Following these large-scale technology demonstrations, and assisted by supportive policies proposed or established in several regions, there are many new CCS projects currently planned for commercial use in the power sector in the U.S. and internationally. CATF's project tracker

420 CATF, *White Paper Comments*, *supra* note 405, at 10.
421 *Id.*

identifies 6 proposed projects on coal power plants and 17 on natural gas projects in the USA. As shown in Tables 2 and 3, 9 of the gas power plants and 3 of the coal power plants have progressed to the FEED study stage, with at least 8 studies completed to date. These FEED studies confirm the readiness and availability of capture technology for all types of fossil fuel-fired power plants, in addition to a diverse range of commercially ready technology vendors.

Table 2. Specifications and status of CCS projects underway in the United States

Project	**Generating capacity**	**CO_2 captured**	**Capture technology**	**Target capture rate**	**Notes**
		NGCC plants			
Panda Energy, TX[422]	420 MW	645,000 to 1 million tons per year depending on capacity factor	MEA (generic)	85%	Existing NGCC, FEED complete
Plant Daniel	375 MW		Linde-BASF	90%	Existing NGCC, FEED complete
Quail Run Energy Center, TX[423]	550 MW	1.5 million metric ton/year	Unannounced	95%	Existing NGCC, FEED, applied for permit
Deer Park Energy Center, TX[424]	1,116 MW	5 million metric ton/year	Shell Cansolv	95%	Existing NGCC, FEED, permit issued
Baytown Energy Center, TX[425]			Shell Cansolv	95%	FEED awarded, permit issued
Delta Energy Center, CA[426]	857 MW	2.3 million metric tons/year	ION	95%	Existing NGCC, FEED

[422] DOE, OFECM, *FOA 2058: Front-End Engineering Design (FEED) Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants* (Sept. 23, 2019) [hereinafter, DOE, *FOA 2058*], https://www.energy.gov/fecm/foa-2058-front-end-engineering-design-feed-studies-carbon-capture-systems-coal-and-natural-gas; *see also* W.R. Elliot, Bechtel Nat'l, Inc., *Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant* (2022), https://www.osti.gov/servlets/purl/1836563.
[423] Texas Comptroller of Pub. Accounts, Data Analysis and Transparency Form 50-296-A for Quail Run Carbon Capture Project, https://assets.comptroller.texas.gov/ch313/1701/1701-ector-quail-appamend1.pdf (last visited Aug. 6, 2023).
[424] DOE, OFECM, *Funding Opportunity Announcement 2515, Carbon Capture R&D for Natural Gas and Industrial Point Sources, and Front-End Engineering Design Studies for Carbon Capture Systems at Industrial Facilities and Natural Gas Plants* (Oct. 6, 2021) [hereinafter DOE, *FOA 2515*], https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial; *see also* Calpine, *Deer Park Energy Center* https://www.calpine.com/deer-park-energy-center (last visited Feb. 6, 2023).
[425] Calpine, *Calpine Carbon Capture: Baytown, Texas*, https://calpinecarboncapture.com/wp-content/uploads/2023/04/Calpine-Baytown-One-Pager-English-1.pdf (last visited Aug. 6, 2023).
[426] DOE, *FOA 2515*, *supra* note 424. *See also* Andrew Awtry, ION Clean Energy, *"Project Delta": Front-End Engineering and Design for a CO_2 Capture System at Calpine's Delta Energy Center* (presented at NETL Carbon Management Project Review Meeting, Aug. 15-19, 2022), https://netl.doe.gov/sites/default/files/netl-

Plant Barry, AL[427]	525 MW	1.5 million metric tons/year	Linde-BASF	90%	Existing NGCC, FEED
Polk Power Station, FL[428]	~280 MW	~800,000 metric tons/year	ION	95%	Existing NGCC, FEED
LG&E Cane Run[429]	700 MW	1.7 million metric tons/year Existing NGCC, FEED	UofK technology	95%	Existing NGCC, FEED
Mustang Station, TX[430]	460 MW	1.6 million metric tons/year	PZAS (piperazine)	90%	Existing NGCC, FEED complete
Chevron Kern River Eastridge, CA[431]	50 MW, steam	300,000 metric tons/year	Svante	N/A	Existing Cogen, Pre-FEED
CalCapture (Elk Hills), CA[432]	550 MW	Up to 1.4 million metric tons/year	NEXT	95%	Existing NGCC, FEED complete
Coyote Clean Power, CO[433]	280 MW	850,000 metric tons/year	Allam-Fetvedt Cycle	100%	New Natural Gas, Allam Cycle, Pre-FEED
Broadwing Clean Energy, IL[434]	280 MW	850,000 metric tons/year	Allam-Fetvedt Cycle	100%	New Natural Gas, Allam Cycle, Pre-FEED

file/22CM_PSC17_Awtry_0.pdf; Calpine, *Our CCUS Projects*, https://calpinecarboncapture.com/ (describing Delta, Baytown and Deer Park carbon capture projects).

427 Sonal Patel, *DOE Backs Carbon Capture Development at Two Major Gas-Fired Power Plants*, Power (Sept. 1, 2022), https://www.powermag.com/doe-backs-carbon-capture-development-at-two-major-gas-fired-power-plants/.

428 DOE, OFECM, *Additional Selections for Funding Opportunity Announcement 2515*, https://www.energy.gov/fecm/additional-selections-funding-opportunity-announcement-2515 (last visited Aug. 6, 2023) [hereinafter DOE, *Additional Selections*]. DOE's Categorical Exclusion Designation Form for the FEED Study suggests that only Unit 2 is the subject of the FEED study. Therefore, the amount of CO_2 subject to the FEED is revised downward from the DOE announcement. DOE, NETL, Categorical Exclusion (CX) Designation Form for Project No. DE-FOA-0002515 (2022), https://www.energy.gov/sites/default/files/2022-11/CX-026914.pdf.

429 DOE, *Additional Selections*, *supra* note 428.

430 DOE, *FOA 2058*, *supra* note 422; *see also* Gary Rochelle et al., *Cost Details from Front-End Engineering Design of Piperazine with the Advanced Stripper* (2022), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4281548.

431 Camille Bond, *Chevron to launch CCS project at Calif. power plant*, EnergyWire (May 19, 2022), https://subscriber.politicopro.com/article/eenews/2022/05/19/chevron-plans-ccs-expansion-in-calif-00033399; Press Release, Chevron, Chevron Launches Carbon Capture and Storage Project in San Joaquin Valley (May 18, 2022), https://chevroncorp.gcs-web.com/news-releases/news-release-details/chevron-launches-carbon-capture-and-storage-project-san-joaquin.

432 Abhoyjit S. Bhown, EPRI, *Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant* (2022), https://www.osti.gov/biblio/1867616/.

433 *Clean Power, Clean Air, Clean Jobs: Coyote Clean Power Project*, Coyote Clean Power, https://coyote.energy/ (last visited Aug. 6, 2023); Sonal Patel, *8 Rivers Unveils 560 MW of Allam Cycle Gas-Fired Projects for Colorado, Illinois*, Power (Apr. 15, 2021) https://www.powermag.com/8-rivers-unveils-560-mw-of-allam-cycle-gas-fired-projects-for-colorado-illinois/.

434 Press Release, 8 Rivers Capital, 8 Rivers Capital ADM Announce Intention To Make Illinois Home To Game-Changing Zero Emissions Project, PRNewswire (Apr. 15, 2021), https://www.prnewswire.com/news-releases/8-

Competitive Power Ventures, WV[435]	1800 MW	Not announced, but greater than 4 million metric tons/year	Unannounced	Unannounced	New NGCC-CCS, early development
Madison Unit 3, LA	600 MW	3.6 to 5.0 million metric tons/year	Unannounced	95%	NGCC, FEED
Lake Charles Power Plant, LA	994 MW	2.5 million million metric tons/year	MHI	95%	Existing NGCC
Coal plants (retrofits)					
Project Tundra, ND[436]	455 MW	3.3 million metric tons/year	Fluor	90%	FEED complete, applied for permit
Dry Fork, WY[437]	400 MW	2.2 million metric ton/year	MTR (membranes)	70%/90%	FEED complete. 90% capture FEED underway.
Dave Johnson, WY[438]	330 MW	1.26 million metric ton/year	Unannounced		Pre- FEED
Gerald Gentleman, NE[439]	700 MW	4.3 million metric tons/year	ION	90%	FEED complete
Prairie State, IL[440]	800 MW	6.2 to 8.2 million metric tons/year	MHI	95%	FEED complete
Four Corners, NM	1540 MW	10 million metric tons/year	MHI	95%	Negotiation for DOE-funded FEED

Internationally, the United Kingdom is particularly active in the development of large-scale CCS for NGCC, summarized in Table 3. In 2015, Shell completed a FEED study for retrofit of 90 percent post-combustion capture to a 400 MW unit at the 1180 MW[441] Peterhead gas plant, only for the plan to be abandoned due to withdrawal of government funding.[442] This study, however,

rivers-capital-adm-announce-intention-to-make-illinois-home-to-game-changing-zero-emissions-project-301269296.html.

435 Press Release, Competitive Power Ventures, Multi-Billion Dollar Combined Cycle Natural Gas Power Station with Carbon Capture Announced in West Virginia (Sept. 16, 2022), https://www.cpv.com/2022/09/16/multi-billion-dollar-combined-cycle-natural-gas-power-station-with-carbon-capture-announced-in-west-virginia/.

436 DOE, *FOA 2058*, *supra* note 422.

437 Tim Merkel et al., Membrane Tech & Rsch., Inc., *Commercial-Scale Front-End Engineering Design (Feed) Study For Mtr's Membrane CO_2 Capture Process* (2022), https://www.osti.gov/biblio/1897679.

438 *Pacificorp may have buyer for its Dave Johnston plant*, argus (Mar. 25, 2019), https://www.argusmedia.com/en/news/1872332-pacificorp-may-have-buyer-for-its-dave-johnston-plant.

439 DOE, *FOA 2058*, *supra* note 422.

440 *Id.*

441 For comparison, the average size of a new NGCC plant installed in the U.S. in 2017 was roughly 800 MW. *See* Glenn McGrath, *Power blocks in natural gas-fired combined-cycle plants are getting bigger*, EIA: Today in Energy (Feb. 12, 2019), https://www.eia.gov/todayinenergy/detail.php?id=38312.

442 Shell U.K. Ltd., *FEED Summary Report for Full CCS Chain*, Doc. No. PCCS-00-MM-AA-7180-00001 (Mar. 22, 2016), https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/531394/11.133_-_FEED_Summary_Report_for_Full_CCS_Chain.pdf .

did not identify any significant technical barriers or risks and received fixed price bids from engineering contractors.

Following a renewed commitment to deploy CCS in the power sector (and more widely) in the UK, several new gas power plant-based proposals[443] are currently undertaking FEED studies and competing to be prioritized in the development of government-supported CO_2 clusters. These are mostly greenfield combined cycle plants with post-combustion capture targeting at least 95 percent capture rates, as specified by the UK's published BAT guidelines for power-CCS.[444] These include Peterhead[445] (900 MW, Scottish Cluster), Keadby 3[446] (900 MW, Humber Cluster), Stallingborough, and BP's Net Zero Teesside Power,[447] as well as various retrofit proposals in less advanced stages of development. If successful, these projects would be supported by the UK's 'Dispatchable Power Agreement,[448] illustrating that—when an appropriate investable business model or regulations are put in place by policy—power companies and technology developers are in a position to deploy CCS-equipped gas plants in the near term. In March 2023, Net Zero Teesside Power was prioritized to enter a contract negotiation stage with the government and could reach final investment decision in early 2024. Expansion of the program to other projects is expected. There are also plans to retrofit CCS to several existing NGCC units in the UK, including a 1240 MW CHP unit at Immingham and RWE's plants at Staythorpe and Pembroke.

In Canada, driven by investment tax credits and carbon pricing, the Genesee project plans to capture at least 95 percent of the CO_2 from the emissions of a new 1300 MW NGCC, and is currently undertaking a FEED study.[449]

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[443] U.K. Dep't for Bus., Energy & Indus. Strategy, *Cluster sequencing Phase-2: eligible projects (power CCUS, hydrogen and ICC)* (Mar. 22, 2022), https://www.gov.uk/government/publications/cluster-sequencing-phase-2-eligible-projects-power-ccus-hydrogen-and-icc/cluster-sequencing-phase-2-eligible-projects-power-ccus-hydrogen-and-icc.

[444] U.K. Env't Agency, *Post-combustion carbon dioxide capture: best available techniques* (2021), https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat; Jon Gibbins & Mathieu Lucquiaud, *BAT Review for New-Build and Retrofit Post-Combustion Carbon Dioxide Capture Using Amine-Based Technologies for Power and CHP Plants Fuelled by Gas and Biomass and for Post-Combustion Capture Using Amine-Based and Hot Potassium Carbonate Technologies on EfW Plants as Emerging Technologies under the IED for the UK* (2022), https://ukccsrc.ac.uk/wp-content/uploads/2023/01/BAT-for-PCC_v2_EfW_web-1.pdf.

[445] Hamish Penman, *Plans for trailblazing Peterhead CCS power station lodged with government*, Energy Voice (Mar. 31, 2022), https://www.energyvoice.com/renewables-energy-transition/ccs/uk-ccs/399875/plans-for-trailblazing-peterhead-ccs-power-station-lodged-with-government/.

[446] SSE Thermal, *Keadby 3 Carbon Capture Power Station Capturing the potential of the Humber*, https://www.ssethermal.com/flexible-generation/development/keadby-3-carbon-capture/ (last visited Aug. 4, 2023).

[447] Press Release, BP, bp and partners (Dec. 15, 2021), https://www.bp.com/en/global/corporate/news-and-insights/press-releases/bp-and-partners-award-first-engineering-contracts-advancing-major-uk-power-and-carbon-capture-projects.html.

[448] U.K. Dep't for Bus., Energy, and Indus. Strategy, *Carbon Capture, Usage and Storage: Dispatchable Power Agreement business model summary and consultation* (2022), https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1068408/Dispatchable_Power_Agreement_Business_Model_Summary_and_Consultation__April_2022_.pdf.

[449] Press Release, Capital Power, Capital Power advances plans for Genesee CCS Project (Dec. 1, 2022), https://www.capitalpower.com/media/media_releases/capital-power-advances-plans-for-genesee-ccs-project/.

Table 3. International examples of proposed CCS plants in the power sector

Project	**Generating capacity**	**CO_2 captured**	**Capture technology**	**Target capture rate**	**Notes**
Genesee 1 and 2, Alberta Canada[450]	1,360 MW	3 million metric tons/year	MHI	95%	Repower coal plant with NGCC-CCS, FEED underway
Peterhead, UK[451]	910 MW	1.5 to 2 million metric ton/year	MHI	95%	New NGCC, FEED underway
Keadby, UK[452]	910 MW	1.5 million metric ton/year	Aker	95%	New NGCC, FEED underway
Net-Zero Teesside, UK[453]	860 MW	Up to 2 million metric tons/year	Aker or Shell Cansolv	95%	New NGCC, FEED underway. In negotiation phase for DPA contract.
VPI Immingham CHP[454]	1,240 MW	Up to 3 million metric tons/year	Shell Cansolv	Up to 95%	NGCC retrofit, FEED underway
Staythorpe, UK[455]	1,700 MW	Not announced	Not announced	Not announced	NGCC retrofit

C. Permits

CCS is demonstrated, economical, and available on power plants, as further evidenced by companies that are applying for and receiving air permits to build it at scale.These at-scale permits are a recent development. All were filed in 2023, within a year of enacting the IRA 45Q tax credits valued at $85/ton for saline storage and $60/ton for EOR. These air permit applications include the following CCS retrofits:

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[450] *Id.*; *see also Press Release, Burns & McDonnell, Burns & McDonnell Delivers on Capital Power's Genesee Repowering Project* (Sept. 29, 2021), https://www.burnsmcd.com/news/capital-power-genesee-repowering-project.

[451] SSE Thermal, *Peterhead Carbon Capture Power Station: Powering on for a net zero Scotland*, https://www.ssethermal.com/flexible-generation/development/peterhead-carbon-capture/ (last visited Aug. 4, 2023); *see also* Mitsubishi Heavy Industries, *MHI and MHIENG Awarded FEED Contract Relating to a GTCC Power Plant and CO_2 Capture Plant for a Power Station in Scotland* (Aug. 30, 2022), https://www.mhi.com/news/22083001.html.

[452] SSE Thermal, *Keadby 3 Carbon Capture Power Station Capturing the potential of the Humber*, *supra* note 446.

[453] Net Zero Teesside Power, https://www.netzeroteesside.co.uk/project/ (last visited Aug. 4, 2023).

[454] Press Release, Shell Global, Shell's Cansolv CO2 Carbon Capture Technology at VPI Immingham (Feb. 3, 2022), https://www.shell.com/business-customers/catalysts-technologies/resources-library/trade-release-shell-catalysts-and-technologies-carbon-capture-technology-at-vpi.html.

[455] Press Release, Kelly Nye, RWE, RWE enters partnership with Harbour energy to explore CCS opportunities at UK power stations (Dec. 20, 2022), https://www.rwe.com/en/press/rwe-generation/2022-12-20-rwe-enters-partnership-with-harbour-energy-to-explore-ccs-opportunities-at-uk-po/; Press Release, Kelly Nye, RWE, RWE announces development proposals for three new carbon capture projects across the UK (May 23, 2023), https://uk-ireland.rwe.com/press-and-news/2023-05-23-rwe-announces-development-proposals-for-three-new-carbon-capture-projects-across-the-uk/.

- Deer Park NGCC in Harris County, Texas. Deer Park is a 1116 MW NGCC plant. Carbon capture equipment will remove 5 million tons/year, 95 percent of the CO_2 emitted from all five steam turbines at the facility. CCS equipment will be constructed in two trains consisting of "(1) Two Quencher columns, where flue gas is conditioned and prepared for the absorption process; (2) Two Absorber columns, where CO_2 is absorbed into the solvent through a chemical reaction; and (3) one Regenerator (or stripper) vessel, where the concentrated CO_2 is released and the original solvent is recovered and recycled back through the process." The permit application was received by the Texas Commission on Environmental Quality (TCEQ) on February 7, 2023 and issued on March 23, 2023.[456]
- Quail Run NGCC in Ector County, Texas. Quail Run Energy Center is a 550 MW plant. Carbon capture will remove about 1.5 million tons/year of CO_2. The application for carbon capture was filed with TCEQ on June 28, 2023.[457]
- Baytown NGCC in Chambers County, Texas. The Baytown facility is 810 MW, consisting of "three Westinghouse 501F CTG turbines with duct fired HRSGs, two auxiliary boilers, one steam turbine generator and ancillary equipment. Each of the three existing turbines are nominally rated between 170 and 190 MW based upon ambient conditions." The plant will use two CCS trains to capture from the three combustion turbines. The capture equipment is designed to remove 95 percent or more of the flue gas it treats, up to 2 million tons/year CO_2. The permit was filed on April 13, 2023 and issued a final permit by TCEQ on May 12, 2023.[458]
- Milton R. Young coal plant in Oliver County, North Dakota. The capture system will capture CO_2 from both units (250MW, 455MW) of the Milton R. Young station. It is designed to remove 13,000 short tons of CO_2 per day. The actual capture from each unit will vary, but could capture 100 percent of unit 1 and 57 percent of unit 2 or 100 percent of unit 2 and 25 percent of unit one. It is designed to remove 95 percent of the CO_2 in flue gas treated. The application was filed on June 2, 2023.[459]

The Quail Run and Milton R. Young applications were filed in June 2023 and regulators have not taken final action yet. Both Deer Park and Baytown were issued as minor modifications less than two months after filing their applications. The rapid approval of these permits supports the view that CCS can be installed on new and existing NGCC units by 2035 and existing coal units by 2030.

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[456] Tex. Comm'n on Env't Quality (TCEQ), Online Records Search for Deer Park Permit Documents, https://records.tceq.texas.gov/cs/idcplg?IdcService=TCEQ_PERFORM_SEARCH&xIdcProfile=Record&IsExternalSearch=1&sortSearch=false&newSearch=true&accessID=3410206&xRecordSeries=0&xInsightDocumentType=0&xMedia=0&select0=xPrimaryID&input0=171713&select1=&input1=&select2=&input2=&select3=&input3=&operator=AND&ftx= (last visited Aug. 4, 2023).

[457] TCEQ, AirPermits IMS - Project Record for Project no. 359380, https://www2.tceq.texas.gov/airperm/index.cfm?fuseaction=airpermits.project_report&proj_id=359380 (last visited Aug. 4, 2023).

[458] TCEQ, Online Records Search for Baytown NGCC Permit Documents, https://records.tceq.texas.gov/cs/idcplg?IdcService=TCEQ_PERFORM_SEARCH&xIdcProfile=Record&IsExternalSearch=1&sortSearch=false&newSearch=true&accessID=3410201&xRecordSeries=0&xInsightDocumentType=0&xMedia=0&select0=xPrimaryID&input0=172517&select1=&input1=&select2=&input2=&select3=&input3=&operator=AND&ftx= (last visited Aug. 4, 2023).

[459] N.D. Dep't Env't Quality, Online Records for DCC East Project LLC Application Documents, https://ceris.deq.nd.gov/ext/nsite/map/results/detail/-8992368000928857057/documents (last visited Aug. 4, 2023).

D. Vendors

Further underscoring the efficacy and availability of carbon capture technology are the guarantees made by the many companies that now offer it. Among the providers of post combustion carbon capture are: Aker Carbon Capture, Aqualung Carbon Capture, BASF Group, BP PLC, Carbon Clean Ltd., C-Capture, Entropy Inc., Fluor Corporation, Honeywell UOP, ION Clean Energy, Inc., Mitsubishi Heavy Industries Ltd., Saipem S.p.A., Shell (CANSOLV), and Svante, Inc. As evidenced by the diversity of vendors listed in Tables 2 and 3, many of these are in a position to bid for large-scale commercial projects in the power sector, typically offering high capture rates of at least 90 percent, and more commonly 95 percent. Since 2012, many of these leading carbon capture solvent providers (including Aker, Cansolv, Fluor, ION, Carbon Clean, MHI) have carried out major test campaigns on combined cycle flue gas at Technology Centre Mongstad (TCM, Norway), at the scale of 80 metric tons per day. Recent test campaigns have included demonstrations of CO_2 capture with flexible plant operation.[460]

Figure 1. Test campaigns by various capture technology vendors on combined cycle flue gas and fluid catalytic cracker flue gas at Technology Centre Mongstad[461]

E. Capture Rates

Techno-economic analysis also indicates that very high levels of CO_2 capture are technically feasible and cost reasonable on gas and coal power plants. The 90 percent benchmark capture rate targeted by many projects until recently has largely emerged by convention as an economically reasonable level of abatement, but does not represent a technical limitation or even an economic optimum for solvent-based capture technology.[462] Increasing the capture rate of these processes typically requires additional absorber height (to prolong the reaction period between flue gas and solvent), and slightly increased desorber temperatures. It should be noted that zero fossil CO_2 emissions (or 100 percent 'effective capture') corresponds to around 99.1 percent capture from an NGCC and 99.7 percent capture from a coal plant.

A detailed engineering study for the IEA Greenhouse Gas Programme by Wood in 2020 examined the cost of equipping a 1.5 GW combined cycle plant with post-combustion capture of 98.5 percent of CO_2 emissions, finding only a 5 percent increase in levelized cost of energy over

[460] Duffy & Thompson, *supra* note 406.
[461] *Wood Report, supra* note 418, at 17
[462] Patrick Brandl et al., *Beyond 90% capture. Possible, but at what cost?*, 105 Int'l J. Greenhouse Gas Control, Feb. 2021, https://www.sciencedirect.com/science/article/abs/pii/S1750583620306642?via%3Dihub.

a 90 percent capture case.[463] This cost increase can be further reduced through implementation of flue gas recirculation to increase CO_2 concentrations in the exhaust gas, which improves capture efficiency and reduces the size of capture equipment. Another recent study reached a similar conclusion: an NGCC plant with CCS capturing nearly 100 percent of the CO_2 in the flue gas was only about 13 percent more expensive on an LCOE basis than an NGCC plant that captures 90 percent of its CO_2.[464] Feron et al. (2019) showed that increasing the effective CO_2 capture rate of a solvent-based capture system (30 percent wt MEA) from 90 percent to 100 percent would give a 1.5 percentage point reduction (34.5 percent to 33 percent) in thermal efficiency on a LHV basis for a ultra-supercritical coal fired power plant, and a 2.2 percentage point reduction for a natural gas fired combined cycle (48.6 percent to 46.4 percent LHV).[465] Hirata et al. (2020) investigated a 99.5 percent capture rate for a 650 MWe coal-fired power plant using MHI's KS-1 solvent, finding that a near 100 percent effective capture rate could be achieved with a 3 percent increase in the total annualized cost of CO_2 Capture ($/ton CO_2).[466]

As indicated by the FEED studies and commercial projects listed in Tables 2 and 3, a range of commercial capture technology vendors now explicitly offer capture rates of over 90 percent. For example, Shell advertises that its CANSOLV technology can remove up to 99 percent of CO_2 from a flue gas stream, and it captures at an average rate of about 90 percent.[467] Likewise, MHI advertises that its KM CDR process and proprietary KS-1 solvent recovers more than 90 percent of CO_2 from the target gas.[468] Other companies offering similar assurances include Aker, BASF/Linde, and ION.[469,470] These vendors have also demonstrated high capture rate operation at various pilot and demonstration sites; units designed for 90 percent capture rate can generally be tested at higher rates simply by reducing flue gas flow and changing other parameters. The Shell Cansolv process has been operated at over 99 percent capture at Boundary Dam 3 and at the pilot-scale at Klemetsrud WtE plant.[471] Pilot tests at the National Carbon Capture Center

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[463] IEAGHG, *2020-07 Update techno-economic benchmarks for fossil fuel-fired power plants with CO2 capture* (July 2020), https://www.ieaghg.org/publications/technical-reports/reports-list/9-technical-reports/1041-2020-07-update-techno-economic-benchmarks-for-fossil-fuel-fired-power-plants-with-co2-capture.

[464] Yang Du et al., *Zero- and negative-emissions fossil-fired power plants using CO2 capture by conventional aqueous amines*, 111 Int'l J. Greenhouse Gas Control, Oct. 2021, https://www.sciencedirect.com/science/article/pii/S1750583621002255.

[465] Paul Feron et al., *Towards Zero Emissions from Fossil Fuel Power Stations*, 87 Int'l J. Greenhouse Gas Control 188 (2019), https://sci-hub.se/downloads/2019-07-17/c5/10.1016@j.ijggc.2019.05.018.pdf.

[466] Stavros Michailos & Jon Gibbins, *UPCC: Ultra-High Post-Combustion CO2 Capture, CO-CAP: Collaboration on Commercial Capture* (Apr. 13, 2021), https://terc.ac.uk/wp-content/uploads/upcc_final_web-2.pdf.

[467] *Reducing CO2 emissions in SMR-based hydrogen units*, Shell Catalysts & Technologies, https://catalysts.shell.com/en/cansolv-customer-briefing-note-download (last visited Aug. 4, 2023); Ajay Singha & Karl Stéphenne, *Shell Cansolv CO2 capture technology: Achievement from First Commercial Plant*, 63 Energy Procedia 1678 (2014), https://www.sciencedirect.com/science/article/pii/S1876610214019924.

[468] *CO_2 Capture Technology for Exhaust Gas KM CDR Process*, MHI, https://solutions.mhi.com/ccus/co2-capture-technology-for-exhaust-gas-kmcdr-process/ (last visited Aug. 4, 2023).

[469] BASF & Linde, *Carbon capture, storage and utilisation* (2019), https://www.linde-engineering.com/en/images/Carbon-capture-storage-utilisation-Linde-BASF_tcm19-462558.pdf; Valborg Lundegaard, Aker Carbon Capture, *Q3 2020* (2020), https://akercarboncapture.com/wp-content/uploads/2021/07/aker-carbon-capture-q3-2020-final.pdf.

[470] Andy Awtry, ION Clean Energy, *Design and costing of ION's CO2 capture plant retrofitted to a 700 MW coal-fired power plant* (2021), https://netl.doe.gov/sites/default/files/netl-file/21CMOG_CCUS_Awtry.pdf.

[471] Jacobs et al., *supra* note 409. Truls Jemtland, *Positive test results from the carbon capture and storage pilot in Oslo,* Fortum: ForTheDoers Blog, (Dec. 13, 2019), https://www.fortum.com/about-us/blog-podcast/forthedoers-blog/positive-test-results-carbon-capture-and-storage-pilot-oslo.

(NCCC) using piperazine solvent observed capture rates up to 99 percent, with minimal effect of energy requirements per ton of CO_2 captured (<5 percent increase).[472] MHI's improved KS-21 amine solvent has been successfully tested at 95 to 98 percent at Technology Centre Mongstad (TCM).[473] Capture levels in the range 95 to 99 percent were also observed in pilot-scale tests at TCM using open source solvents MEA and CESAR1 solvents.[474]

The feasibility of high capture rates is further reflected in the UK's BAT Guidelines for CCS power plants, which require at least 95 percent capture.

F. Deployment of Carbon Capture in Other Industries

In recent years, there has been particular emphasis on the application of CCS to heavy industry sectors, such as cement, steel, refining, fertilizers and petrochemicals. Many of these sectors include emissions sources which are very costly or impossible to abate by means other than carbon capture and storage, often known as 'hard-to-abate.' Some industrial sources of CO_2 produce streams with higher CO_2 concentrations and fewer impurities than power plant emissions, and therefore represent the majority of experience with large-scale carbon capture and storage to date. These include natural gas processing, bioethanol, fertilizer production, and hydrogen production (typically for oil refinery applications). These sectors have been pivotal in developing the wealth of commercial experience with CO_2 separation technologies—particularly amine-based solvents—which are now being more widely applied to the power sector.[475] Amine-based solvents were first applied to the removal of CO_2 from natural gas in the 1930s and are routinely used in the production of ammonia-based fertilizers. The Quest CCS project in Alberta, Canada, has used an amine-based process (monodiethanolamine) to remove CO_2 produced during the production of hydrogen from methane and other hydrocarbon gasses. Since 2015, the plant has consistently captured its targeted 1 to 1.2 million metric ton (Mt)/year of CO_2, with an average capture rate of 79 percent (design target is 80 percent) over the first six years of operation.[476]

Experience with such large-scale amine CO_2 capture plants, even with different process gas streams, is highly applicable to the scale up of similar processes in the power sector. This is because using amines to capture CO_2 from flue gas is fundamentally the same process in both cases. Adapting existing amine-based capture technologies to power sector applications involves making adjustments to process parameters such as absorber height, reboiler energy demand, and CO_2 loading in the solvent loading, in accordance with differences in the pressure and CO_2

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[472] Tianyu Gao et al., *Demonstration of 99% CO2 removal from coal flue gas by amine scrubbing*, 83 Int'l J. Greenhouse Gas Control 236 (2018), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3365961.

[473] Press Release, MHI, Mitsubishi Heavy Industries Engineering Successfully CompletesTesting of New "KS-21TM" Solvent for CO_2 Capture (Oct. 19, 2021), https://www.mhi.com/news/211019.html.

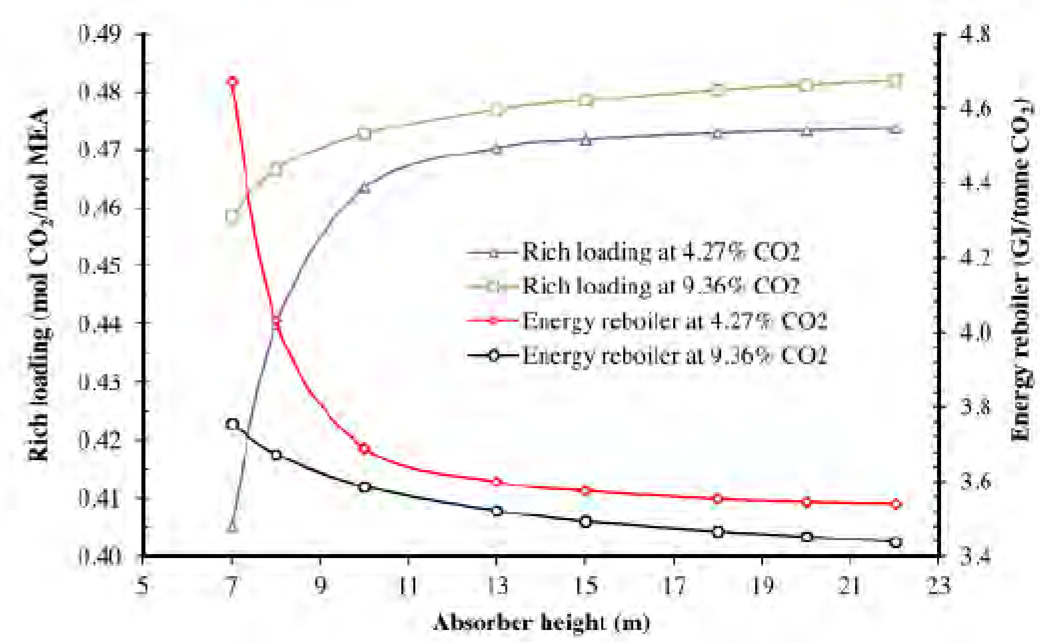
[474] Muhammad Shah et al., *CO_2 Capture from RFCC Flue Gas with 30w% MEA at Technology Centre Mongstad, Process Optimization and Performance Comparison* (2018), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3366149; Christophe Benquet et al., *First Process Results and Operational Experience with CESAR1 Solvent at TCM with High Capture Rates (ALIGN-CCUS Project)* (2021), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3814712.

[475] *Wood Report*, *supra* note 418.

[476] Should be Shell Canada Energy, Quest Carbon Capture and Storage Project Annual Summary Report – Alberta Department of Energy 2021 (2022), https://open.alberta.ca/dataset/113f470b-7230-408b-a4f6-8e1917f4e608/resource/e957e772-4fe2-4504-8fea-439120134427/download/quest-annual-summary-report-alberta-department-of-energy-2021.pdf.

concentration of the target gas stream (Figure 2).[477] Appropriate upstream cleaning of the gas stream is also necessary to remove any species that can negatively affect the amine process. See co-benefits discussion in Section E *infra*).

Figure 2. Impact of CO_2 loading on reboiler energy and rich loading for two different flue gas compositions



Amine solvent-based processes are now being applied to a range of other industrial emission sources at commercial scales, many of which treat process streams with similar composition to that of a coal or gas-fired power plant. In the cement sector, capture of 400 kt/year from the Brevik cement plant in Norway is under construction (start of operations expected in 2024), while capture of over 1 Mt/year from a plant in Edmonton is expected from 2026, and 0.8 Mt from Padeswood Cement in the UK from 2027. In Europe, there is also considerable interest in CCS for heat and power plants fired with waste or biomass fuel. For example, Klemetsrud waste-to-energy plant in Norway has begun construction on a 90 percent capture unit (from Shell Cansolv), while two biomass CHP plants in Denmark have taken a final investment decision. Numerous other projects in these sectors and others are in earlier stages of planning.[478]

Besides contributing to technical and commercial experience with CO_2 capture, the deployment of CCS on non-power sources is relevant to the power sector as it will seed and accelerate the development of CO_2 transport and storage networks. Many lower-cost capture sources (e.g., ethanol, hydrogen) will deploy CCS first, helping to build out CO_2 pipeline networks and storage sites which can also be shared by power plants equipped with CCS.

[477] *Wood Report*, *supra* note 418, at 8.
[478] *Europe Carbon Capture Activity and Project Map*, CATF, https://www.catf.us/ccsmapeurope/ (last visited Aug. 4, 2023).

II. Availability of Geologic Sequestration

A. Geologic Storage Has Been Thoroughly Demonstrated

There is a long history of successful injection and retention of CO_2 as well as a variety of other gasses and liquids into geologic formations. These demonstrate that CO_2 can be safely and permanently stored in porous geologic formations below impermeable cap rocks.

Injection of gasses into saline aquifers, salt domes, and depleted gas zones have been routine for decades as a part of America's natural gas storage program. In fact, natural gas storage goes back a century, originally tested in 1915.[479] The National Petroleum Reserve system now safely contains and maintains 3 trillion cubic feet of injected gas in the subsurface on an annual basis.[480] Natural gas storage in geologic formations is, in fact, widespread, with natural gas storage facilities in 30 states, in approximately 400 facilities nationwide, with a combined capacity of about 4 trillion cubic feet of natural gas. Eighty percent of the deep geologic natural gas storage capacity is in depleted oil and gas formations- which themselves are porous formations containing hydrocarbon-bearing saline brines, 10 percent in saline brine-only aquifers, and 10 percent in salt formations.[481]

Liquid injection into geologic formations has a similarly long history. Billions of tons of liquid waste are disposed of into saline aquifers annually.[482] There are approximately 150,000 injection wells in the U.S. in use for disposal of municipal wastewater, produced fluid brine waste from natural gas storage, unconventional gas production and brines produced during EOR.

Geologic storage of CO_2 is a well-understood practice in the U.S. and worldwide, with commercial operations dating back to the 1970s. To date, in the U.S. alone, over 31 Mt of CO_2 emissions have been safely and permanently stored in deep geologic formations regulated under EPA's Underground Injection Control authority, and monitored under Clean Air Act Greenhouse Gas Monitoring and Reporting requirements.[483]

Additionally, geologic storage of CO_2 into saline aquifers is adequately demonstrated at the commercial scale in the U.S. and globally. The first commercial saline storage project in the world, dating back to 1996—Sleipner in Norway—has stored approximately 1 Mt of captured CO_2 annually for over 20 years in deep geologic formations beneath the North Sea.[484] The Sleipner project's multi-decade record of geologic storage provides precedent that deep geologic storage of commercial volumes of captured CO_2 can be effectively and safely performed. Domestically, the two Decatur saline storage projects provide proof that carbon storage is available at commercial scale. The Illinois Basin Decatur Project has successfully and securely stored over 1 million metric tons of CO_2 into the Mount Simon sandstone formation in the Illinois Basin. The sister commercial project, the Illinois Industrial CCS project, is currently

[479] *See* NETL, *Underground Natural Gas Storage – Analog Studies to Geologic Storage of CO_2* (2019), https://www.osti.gov/servlets/purl/1492342.
[480] EIA, *Weekly Natural Gas Storage Report*, https://ir.eia.gov/ngs/ngs.html.
[481] API, *Underground Natural Gas Storage*, https://www.energyinfrastructure.org/energy-101/natural-gas-storage.
[482] Elizabeth J. Wilson, Timothy L. Johnson & David W. Keith, *Regulating the Ultimate Sink: Managing the Risks of Geologic CO_2 Storage*, 37 Env't Sci. & Tech. 3476 (2003), https://pubs.acs.org/doi/pdf/10.1021/es021038%2B.
[483] 40 C.F.R. §§ 98.440–.449 (subpart RR).
[484] Anne-Kari Furre et al., *20 Years of Monitoring CO_2-injection at Sleipner*, 114 Energy Procedia 3916 (2017).

underway injecting and storing commercial volumes of CO_2 each year, with a five-year permit to inject 5.5 Mt over the life of the project.[485] This experience with storage of CO_2 in saline formations is further supported by the wealth of experience with injecting CO_2 into existing oil fields as part of the enhanced oil recovery process. As part of the EOR process, approximately 1.4 billion tons of new (and much more recycled) CO_2 has been injected into porous sandstone and carbonate formations containing oil-bearing brines.

B. Storage Opportunities Are Well-Dispersed and Within Reasonable Distance of Gas- and Coal-Fired Power Plants Across the Country

The U.S. has widespread and abundant geologic storage options in deep saline aquifers. Geologic storage of CO_2 is widely available to reduce carbon emissions from fossil fuel-fired power plants and other large point sources. The U.S. Department of Energy (DOE) Carbon Sequestration (NATCARB) Atlas estimates a median storage potential of over 8,000 Gt in saline formations in the U.S., which are spread across multiple sedimentary basins.[486] This estimate of domestic saline storage capacity represents over 1,000 years' worth of emissions from U.S. NGCCs. The NATCARB Atlas and database are underpinned by two decades of research and demonstration, including hundreds, if not thousands, of technical publications based on millions of tons of CO_2 injected into saline aquifers and depleted oil fields.

[485] Press Release, ADM, *ADM Begins Operations for Second Carbon Capture and Storage Project* (Apr. 7, 2017), https://www.adm.com/en-us/news/news-releases/2017/4/adm-begins-operations-for-second-carbon-capture-and-storage-project/; Scott McDonald, ADM, *Illinois Industrial Carbon Capture & Storage Project: Eliminating CO_2 Emissions from the Production of Biofuels: A 'Green' Carbon Process*, https://www.energy.gov/sites/prod/files/2017/10/f38/mcdonald_bioeconomy_2017.pdf.
[486] NETL, DOE, *Carbon Storage Atlas* (5th ed.), https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.

Figure 3. Map developed by Carbon Solutions, LLC using NATCARB data, illustrating generalized saline storage potential in the U.S.[487]

Most U.S. regions have begun to lay the groundwork for more extensive CCS project deployment, with the potential for commercially storing significant CO_2 emissions in deep saline aquifers.

Table 4. NATCARB saline storage capacities and number of CarbonSAFE projects within each U.S. storage region as defined by the Regional Carbon Sequestration Partnership initiatives

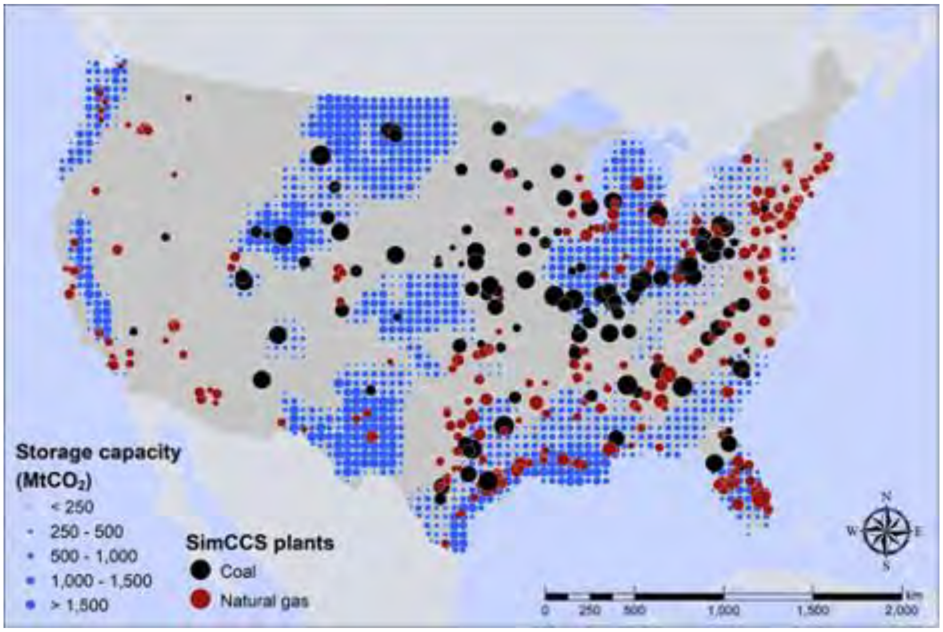
	United States Storage Regions								
	Big Sky	Midwest	Midwest/Mid-Atlantic	Plains	Southeast	Southwest	West Coast	Other Non-RCSP Region	Total
States Included	ID, MT, and WY	IL, IN, and KY	MD, MI, NJ, NY, OH, PA, and WV	IA, MN, MO, ND, NE, SD, and WI	AL, AR, FL, GA, LA, MS, NC, SC, TN,	AZ, CO, KS, NM, OK, West TX,	CA, NV, OR, and WA	AK, CT, DC, DE, HI, MA, NH, RI, VT,	
NATCARB Atlas V CO2 Saline Storage Medium Resource Estimate (Gt)	805	163	122	583	5,257	1,000	398	not estimated	8,328
CarbonSAFE Phase I, II, and III Projects	4	4	2	5	4	3	2	-	24

Saline storage opportunities are widespread across the U.S. and much of the existing fossil fuel-fired power plants are located on top of or in proximity to sedimentary basins with significant saline storage capacity. Figure 4 shows generalized saline storage capacity with existing coal and natural gas-fired power plant locations superimposed (137 coal plants, totaling 603 $MtCO_2$/yr; 293 natural gas plants totaling 444 $MtCO_2$/yr). This map is overinclusive and includes many more plants than would be subject to CCS-based standards under this rulemaking. The sources in

[487] Carbon Solutions, LLC, *Clean Air Task Force: Final Report* 21 (Sept. 21, 2022) [Attachment 8].

the map consist of all fossil fuel-fired plants that plan to operate in 2030 and that operate over 30 percent capacity factor.

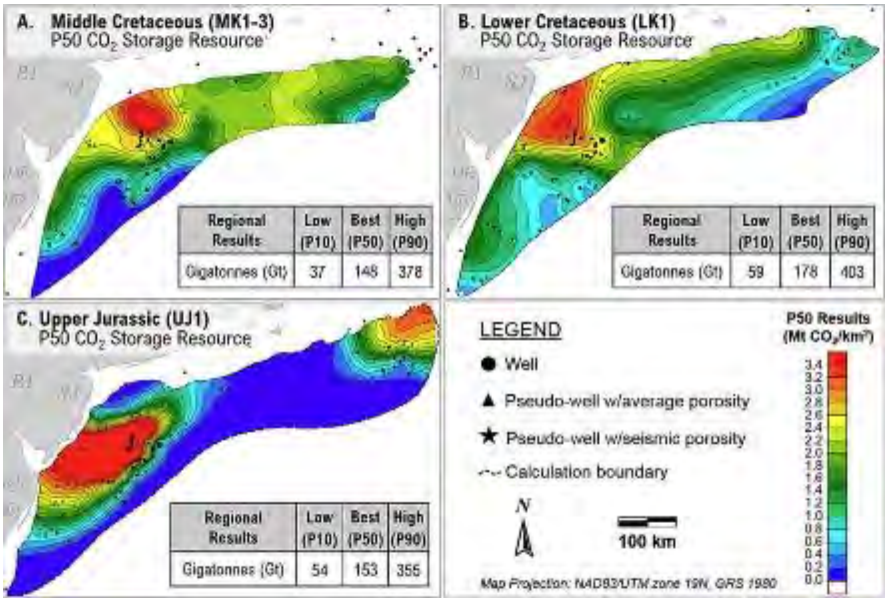
Figure 4. Map of U.S. saline storage capacity with locations of coal and natural gas-fired power plants[488]



Additionally, significant saline storage potential has been identified in the offshore Mid-Atlantic region (see Figure 5 below). Battelle Memorial Institute led a DOE-sponsored consortium to investigate storage opportunities in the Mid-Atlantic offshore region including the Baltimore Canyon Trough and the Georges Banks Basin.[489] The results of the study suggest that deep saline formations in this offshore region may be able to store hundreds of millions to billions of tons of CO_2, which could serve as an important storage resource for fossil fuel-fired power plants in the Northeast region. DOE's Office of Fossil Energy and Carbon Management recently announced a new funding award to establish a foundation for a carbon management hub along the Mid-Atlantic Outer Continental Shelf from Northern Virginia to Massachusetts which builds on the previous characterization work performed in this region.[490]

[488] *Id*. at 21 (Sept. 21, 2022) [Attachment 8].
[489] Battelle, *Mid-Atlantic U.S. Offshore Carbon Storage Resource Assessment Project (Final Technical Report)* (2019), https://www.osti.gov/biblio/1566748-mid-atlantic-offshore-carbon-storage-resource-assessment-project-final-technical-report.
[490] DOE, OFECM, *Project Selections for FOA 2799: Regional Initiative to Accelerate Carbon Management Deployment: Technical Assistance for Large Scale Storage Facilities and Regional Carbon Management Hubs*, https://www.energy.gov/fecm/project-selections-foa-2799-regional-initiative-accelerate-carbon-management-deployment.

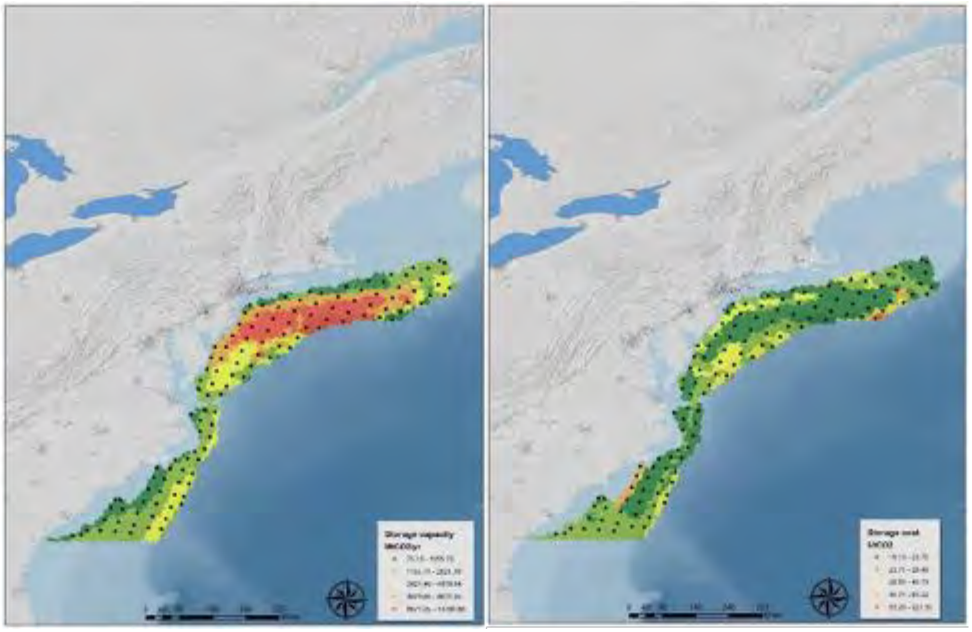
Figure 5. *Map of Offshore Storage Capacity in the Mid-Atlantic*[491]



Recent CATF-commissioned work by Carbon Solutions, LLC, shows that offshore storage opportunities in the Atlantic extend much further along the Eastern Seaboard (*see* Figure 6), from Massachusetts to Georgia, and could serve as an important storage resource for much of the East Coast.[492]

[491] Battelle, *supra* note 489.
[492] Carbon Solutions, LLC, *Oceankind: CCS Potential in the US Mid-Atlantic using Offshore Storage* 7 (May 19, 2023) [Attachment 9].

Figure 6. Map of Offshore Storage Capacity Along the Eastern Seaboard[493]



Depleted oil fields also contain significant storage capacity. Carbon dioxide is currently injected into many fields for enhanced oil recovery. The injected CO_2 is stored in the process of injection, production, and recycling. This "incidental" or "associated" storage occurs when CO_2 is trapped in rock pore spaces by the capillary physics process of releasing oil during CO_2 flooding.

The structure of the 45Q tax incentive, which provides a larger tax credit for saline storage than use of CO_2 in EOR, means that saline storage is likely to be preferred wherever low-cost saline storage formations are available for storage. But it is feasible to use oil fields where saline storage options are not available or where storage in such formations is more expensive. As of end-of-year 2020, there were approximately 142 CO_2-EOR projects actively injecting CO_2 in the deep subsurface in the U.S.[494] This includes an estimated 1.3 billion cubic feet per day of naturally occurring CO_2 that is mined from underground deposits and transported to currently active EOR projects. This currently-mined CO_2 at existing EOR fields could be replaced with captured CO_2 from power plants. In addition, the United States Geological Survey (USGS) has estimated that there are over 25 billion barrels of oil that are technically recoverable via EOR across 3,500 screened oil reservoirs.[495] Existing oil and gas fields could be used for storage of CO_2 without EOR.

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[493] *Id.*

[494] Advanced Resources International, *The U.S. CO_2 Enhanced Oil Recovery Survey* (Oct. 21, 2021), https://adv-res.com/pdf/ARI-2021-EOY-2020-CO2-EOR-Survey-OCT-21-2021.pdf.

[495] *See* USGS, *National Assessment of Carbon Dioxide Enhanced Oil Recovery and Associated Carbon Dioxide Retention Resources—Summary* (2020), https://pubs.usgs.gov/fs/2021/3057/fs20213057.pdf.

C. Significant Investment from DOE Continues to Demonstrate and Validate Large-Scale Storage Opportunities

The U.S. has performed more CCS research, and has more CCS activities ongoing and planned, than any other country.[496] DOE has invested more than $1 billion during the past two decades through its Carbon Storage Research and Development Program to develop the technologies and capabilities for widespread commercial deployment of geologic storage.[497] Some of the selected programs and initiatives include the Regional Carbon Sequestration Program (RCSP),[498] more recently initiated Regional Initiatives to accelerate CCS deployment,[499] the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative,[500] the NATCARB Carbon Storage Atlas,[501] efforts to characterize storage potential and prospects in the offshore Gulf of Mexico,[502] and is considering establishment of a multi-year field-based research and development initiative named Carbon Storage Technology Operations and Research (CarbonSTORE).[503] The result of this work has demonstrated that the U.S. may have some of the most abundant natural resources for storage of any country in the world.

In late 2016, in a follow-up to the successful decade-long RCSP effort, DOE initiated a new phase of its efforts to advance carbon storage technology by launching the CarbonSAFE program. The CarbonSAFE program was initially awarded $44 million to support and promote the development of carbon storage sites with the potential to store over 50 Mt of CO_2 by 2026, building on learnings from the RCSP program.[504] The program is comprised of four phases, covering pre-feasibility through construction:

Phase I: Integrated CCS Pre-Feasibility (12 to 18 month initiative)

- Formation of a team; development of a feasibility plan; and high-level technical evaluation of the sub-basin and potential CO_2 sources
- *Thirteen projects funded*
  - Integrated Midcontinent Stacked Storage Hub
  - Nebraska Integrated Carbon Capture and Storage Pre-feasibility Study

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[496] CEQ, *Report to Congress on Carbon Capture, Utilization, and Sequestration* (2021), https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf; *see also* CATF, *U.S. Carbon Capture Activity and Project Map*, https://www.catf.us/ccsmapus/.
[497] NETL, *Safe Geologic Storage of Captured Carbon Dioxide: Two Decades of DOE's Carbon Storage R&D Program in Review* (Apr. 13, 2020), https://www.netl.doe.gov/node/9687.
[498] NETL, *Regional Carbon Sequestration Partnership (RCSP)*, https://www.netl.doe.gov/coal/carbon-storage/storage-infrastructure/regional-carbon-sequestration-partnerships-initiative.
[499] DOE, OFECM, *FOA 2000: Regional Initiative to Accelerate CCUS Deployment*, https://www.energy.gov/fe/foa-2000-regional-initiative-accelerate-ccus-deployment.
[500] NETL, *CarbonSAFE Initiative*, https://www.netl.doe.gov/coal/carbon-storage/storage-infrastructure/carbonsafe.
[501] NETL, *NATCARB/Atlas*, https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas.
[502] Gulf Coast Carbon Ctr., *GoMCarb*, https://www.beg.utexas.edu/gccc/research/gomcarb; S. States Energy Bd., *SECARB Offshore*, https://www.sseb.org/programs/offshore/.
[503] NETL, *DOE Seeks Information on Developing Carbon Storage Field Laboratories* (Dec. 2, 2022), https://netl.doe.gov/node/12225.
[504] NETL, *CarbonSAFE Initiative*, *supra* note 500; DOE, *Energy Department Announces More than $44 Million for CO_2 Storage Projects* (Nov. 30, 2016), https://www.energy.gov/articles/energy-department-announces-more-44-million-co2-storage-projects.

    - Integrated Carbon Capture and Storage for Kansas
    - Integrated Commercial Carbon Capture and Storage Pre-feasibility Study at Dry Fork Station, Wyoming
    - CarbonSAFE Illinois East Basin
    - Central Appalachian Basin CarbonSAFE Integrated Pre-feasibility Project
    - Northern Michigan Basin CarbonSAFE Integrated Pre-feasibility Project
    - Integrated Pre-feasibility Study for CO_2 Geological Storage in the Cascadia Basin, Offshore Washington State and British Columbia
    - California CO_2 Storage Assurance Facility Enterprise
    - Integrated CCS in the Louisiana Chemical Corridor
    - Integrated CCS Pre-feasibility in the Northwest Gulf of Mexico
    - CarbonSAFE Rocky Mountains
    - Integrated Pre-feasibility Study of a Commercial-scale CCS Project in Formations of the Rock Springs Uplift, Wyoming

Phase II: Storage Complex Feasibility (18 to 24 month initiative)

- Data collection; geologic analysis; analysis of contractual and regulatory requirements; subsurface modeling; risk assessment; evaluation of monitoring requirements; and public outreach
- *Six projects funded*
    - Integrated Midcontinent Stacked Carbon Storage Hub: Storage Complex Feasibility Assessment
    - Commercial-scale Carbon Storage Complex Feasibility Study at Dry Fork Station, Wyoming
    - Wabash CarbonSAFE
    - CarbonSAFE Illinois Macon County
    - Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi
    - North Dakota Integrated Carbon Storage Complex Feasibility Study

Phase III: Site Characterization and Permitting (<3-year initiative)

- Detailed site characterization; submit UIC Class VI permit to construct; CO_2 capture assessment; NEPA approvals
- *Five projects funded*
    - North Dakota CarbonSAFE
    - Accelerating CCUS at Dry Fork Station, Wyoming
    - Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi
    - Illinois Storage Corridor
    - San Juan Basin CarbonSAFE

Phase IV: Construction (<2.5-year initiative)

- Obtain Class VI permit to inject; drill and complete injection and monitoring wells; complete risk and mitigation plans
- Subject to funding availability

The CarbonSAFE projects, building off of results of the decade-long NETL RSCP program, have already begun to publish important findings, most importantly, the potential for vast regional, and inexpensive ($2 to $4/ton) sequestration hub at the Kemper County, Mississippi site (ECO2S), and the Illinois Basin Decatur Project (IBDP)—demonstrating that large saline storage aquifers are readily available for storage in the Midwest and Southeast:

Project ECO2S in Kemper County, Mississippi is a DOE- and Southern Company-supported CarbonSAFE initiative with the goal of developing a commercial scale CO_2 storage site. Southwest regional development began with the initial characterization of potential storage formations done by the NATCARB Atlas initiative and the Plant Daniel pilot project in Mississippi, which successfully injected 3,000 metric tons of CO_2 and developed characterization, permitting, public outreach, injecting and monitoring methodologies. The RCSP Citronelle deployment project in Alabama built on the knowledge base established at the Plant Daniel project to further prove the feasibility of CO_2 storage in the gulf coast region. These initial efforts provided important knowledge of regionally significant geologic formations, as well as improved techniques and technologies to monitor and model CO_2 storage sites. The Project ECO2S site builds on this operational expertise, technical engineering, and monitoring methodologies, further demonstrating the feasibility of commercial-scale CO_2 storage.

One of the most active regions of carbon storage development has been the Midwest's Illinois Basin. The Mount Simon sandstone has proved to be a world-class storage formation in Illinois through multiple projects conducted by public-private partnerships. Initial Midwest Geological Sequestration Consortium (MGSC) validation phase projects proved CO_2 could be safely injected and stored in regional formations. The Illinois Basin Decatur Project (IBDP), organized by MGSC, followed the validation projects and injected one million metric tons of CO_2 from 2011 to 2014 near the Archer Daniels Midland Company ethanol plant. Lessons learned from the IBDP project led to the Illinois Industrial Carbon Capture and Storage Project (ICCS), which continues to inject commercial volumes of CO_2 annually. This project is further proving the safe storage capabilities of the Mount Simon sandstone and demonstrating the safe and permanent storage of CO_2. The project is also allowing for further improvement of modeling techniques, and other technical knowledge and expertise for commercial-scale storage projects. Currently, DOE is supporting the development of the CarbonSAFE Illinois Storage Corridor, where the goal is to develop a storage project with the capability of injecting 50 million metric tons of CO_2 per year.

These government-funded projects have established the foundation for announced plans for subsequent, commercial-scale projects and have successfully demonstrated commercial-scale storage, while improving our understanding of project screening, site selection, characterization, baseline monitoring, verification, and accounting, and injection operations. Lessons learned from these projects are being applied elsewhere across multiple sedimentary basins in the U.S., and the additional CarbonSAFE projects that are currently funded, and projects that will be funded in the future, will continue to validate and broaden the availability of commercial-scale storage.

The IIJA provided DOE with $2.25 billion of funding, to be used by FY26 to build on the CarbonSAFE program by providing grant funding for the development of new or expanded commercial large-scale storage projects, including Phase III, III.5, and IV funding for the feasibility, site characterization, permitting, and construction stages of project development. On May 17, 2023, DOE announced the re-opening of this funding and nine projects were selected for a total of $242 million in funding to support the development of new and expanded large-scale commercial storage projects with capacities to securely store more than 50 million or more metric tons of CO_2.[505] These projects will focus on the detailed site characterization, planning, and permitting stages of project development under Phase III of CarbonSAFE:

- *Bluebonnet Sequestration Hub* - TX
- *Lone Star Storage Hub Project* - TX
- *CarbonSAFE Eos: Developing Commercial Sequestration for Southern Colorado* - CO
- *Magnolia Sequestration Project* - LA
- *Longleaf CCS* - AL
- *Timberlands Sequestration Project* - AL
- *Illinois Basin West CarbonSAFE* - IL
- *Coal Creek Carbon Capture: Site Characterization and Permitting* - ND
- *CarbonSAFE Phase III: Sweetwater Carbon Storage Hub* - WY

Additionally, in 2019, the Regional Initiative to Accelerate Carbon Capture, Utilization, and Storage Deployment was launched by DOE to identify and address regional storage and transport hurdles affecting commercial deployment of CCS.[506] The regional initiatives build upon the research, expertise, and stakeholder base established by the RCSPs to continue identifying and addressing regional knowledge gaps. Four regional initiatives were originally selected to facilitate and integrate CarbonSAFE projects and commercial efforts within the regions:

- Midwest Regional Carbon Initiative
- Carbon Utilization and Storage Partnership of the Western United States
- Southeast Regional Carbon Utilization and Storage Partnership
- Plains Carbon Dioxide Reduction Partnership

These regional initiatives will further accelerate the commercial deployment of CCS across the U.S. by promoting regional technology transfer, addressing key technical challenges, facilitating data collection, sharing, and analysis, and evaluating existing regional infrastructure.

DOE also recently announced project selections for its regional initiative, 16 projects totaling nearly $25 million in DOE funding, under two areas of interest; 1) technical assistance and public engagement for geologic CO_2 storage and transport at large-scale storage facilities or within prospective regional carbon management hubs, and 2) state geological data gathering, analysis, sharing, and engagement.

Area of interest 1 projects funded:

- *Supporting Communities and Industry for Mid-Atlantic Offshore Carbon Storage Hub Development*
- *Project WyoTCH: Developing a Roadmap for a Sustainable Carbon Hub*
- *CUSP: Four Corners Regional Initiative*

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[505] DOE, OFECM, *Project Selections for FOA 2711: Carbon Storage Validation and Testing (Round 1)*, https://www.energy.gov/fecm/project-selections-foa-2711-carbon-storage-validation-and-testing-round-1.
[506] NETL, *Regional Initiative to Accelerate CCUS Deployment*, https://netl.doe.gov/carbon-management/carbon-storage/regional-initiative-to-Accelerate-CCUS-deployment.

- *Anadarko Basin Carbon Management Hub*
- *Liberty Carbon Management Hub*
- *Texas Louisiana Carbon Management Community*

Area of interest 2 project funded:

- *Assess and Provide Pertinent Data and Information to an Emerging CCUS Industry with the Goal of Accelerating CO_2 Sequestration in Cook Inlet Region*
- *Oklahoma Geological Survey Coordination of Mid-Continent Carbon Management*
- *A Play-Based Exploration of CCS Potential of the Illinois Basin*
- *Alabama Carbon Storage: Data Sharing and Engagement*
- *Subsurface Seismic Structural Characterization of the Hogback Monocline and Thermal Characterization of the San Juan Basin, New Mexico*
- *The Central Appalachian Partnership for Carbon Storage*
- *Characterization of Subsurface Opportunities to Accelerate CCUS in Indiana*
- *Wyoming Class VI Site Characterization Database*
- *Utah Statewide Carbon Storage Assessment: Geological Data Gathering, Analysis, Sharing, and Engagement*
- *Advancing CCUS in the Michigan Basin*

D. Additional Analysis by Carbon Solutions Shows Feasibility of CCS Deployment by the U.S. Power Sector

1. CCS Is Technically and Economically Viable for the the Gas and Coal Fleets

The Carbon Solutions, LLC report titled "National Assessment of Natural Gas Combined Cycle and Coal-fired Power Plants with CO_2 Capture and Storage" commissioned by Clean Air Task Force had the objective to determine the techno-economic feasibility of CCS deployment for the U.S. fossil-fired power fleet and what percentage of the existing fleet has reasonable (technical and economical) access to storage.[507]

The study uses SimCCS^{PRO} toolsets to perform a first-of-its-kind advanced source-sink analysis, developing multiple CCS buildout scenarios connecting gas and coal plants to CO_2 storage strictly in onshore saline aquifers. The goal of the study was to determine the techno-economic feasibility of national-scale CCS buildout for the existing power fleet. The study was done prior to passage of the Inflation Reduction Act and focused on power plants that were expected at that point to be operational in 2030 and beyond but did not include plants with announced retirements prior to 2030. Because the study was done prior to the passage of the Inflation Reduction Act, it does not anticipate any of the changes in the sector that are expected to occur as a result of that Act, including the changes anticipated in the business-as-usual scenario modeled by EPA in the Integrated Planning Model. As a result, the study evaluates the application of CCS at more power plants than are expected to deploy CCS in EPA's model, or even expected to remain online post-2030 given IRA tax incentives for alternative generation resources.

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[507] Carbon Solutions, LLC, *National Assessment of Natural Gas Combined Cycle (NGCC) and Coal-fired Power Plants with CO2 Capture and Storage (CCS)* (Sept. 2022) [Attachment 11].

This study also does not provide any specific pipeline locations but instead provides illustrative corridors that link sources and sinks. It is also not a recommendation or expectation that any particular pipeline infrastructure will be built out as each plant owner will determine how to comply with the proposed standards. What the study does is demonstrate that the bulk of the existing gas and coal fleet can technically and economically access sequestration if it is subject to a CCS-based performance standard and chooses to comply with it through a CCS retrofit. Storage sites were aggregated on a 50 km grid, avoiding urban areas, national parks, and other infeasible surface features.

2. Capture

Carbon Solutions sourced CO_2 capture data (capturable CO_2, number of CO_2 streams, and CO_2 stream purity) from NICO_2LE database that fuses and analyzes CO_2 emissions data from multiple data sources to calculate capturable CO_2. Capture costs for coal and NGCC power plants are derived from Brown and Ung (2019) with lower-bound estimates for Nth-of-a-kind plants, assuming a 11 percent capital recovery factor to annualize capital costs.[508] Power plant information was generated from the US EPA Emissions and Generation Resource Integrated Database (eGRID), and power plants were characterized by their dominant fuel type (coal or natural gas). Individual gathering units or entire plants that were due to close before 2030 were excluded from the analysis. Average capture costs across the modeled buildout scenarios ranged from \$68.30 to \$70.37/ton CO_2.

Source Parameters:

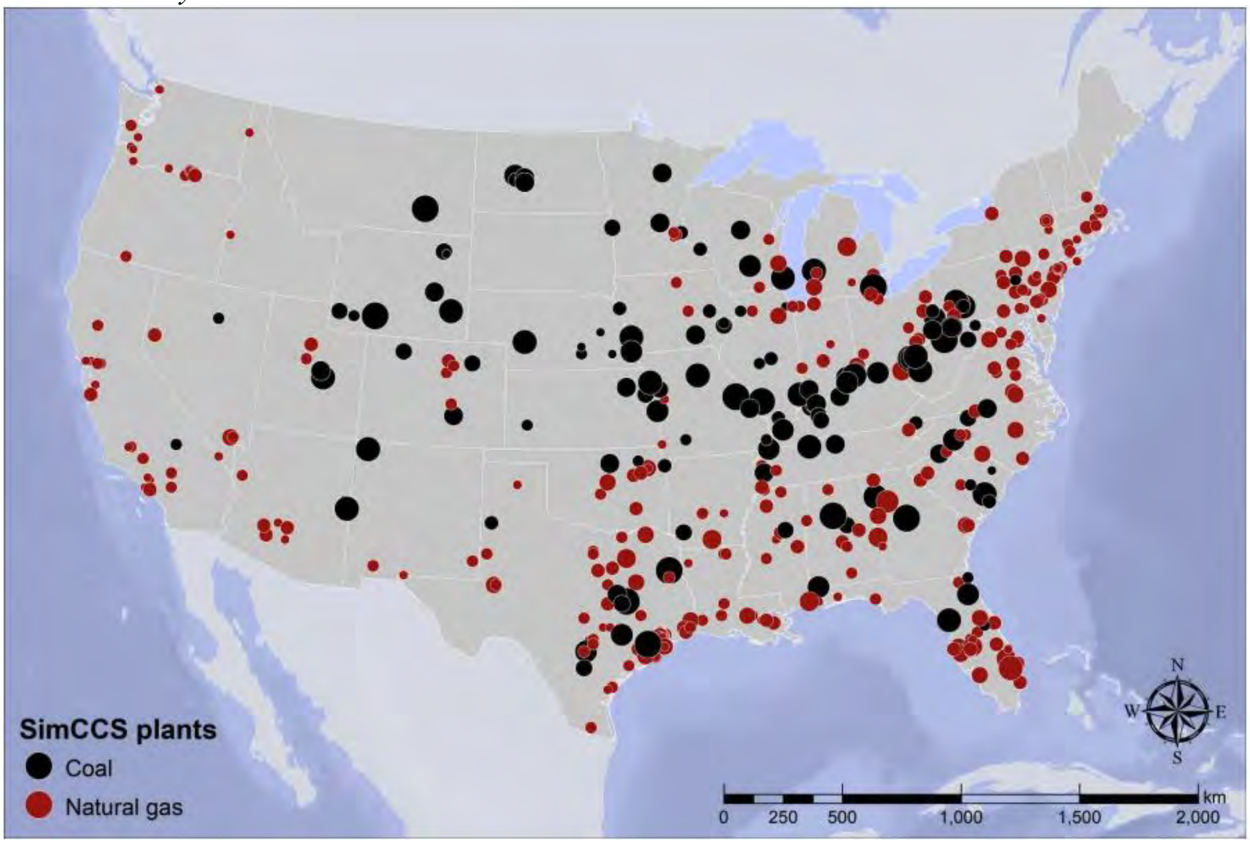
- Fuels: All coals, NG
- Min. Capture: 0.5 MtCO_2/yr
- Capture Rate: 90 percent
- Retirements: 2030
- Capacity Factor: 30 percent

Sources:

- 429 plants | 1,044 MtCO_2/yr
- 136 coal | 600 MtCO_2/yr
- 293 NGCC | 444 MtCO_2/yr

[508] Jeffrey D. Brown & Poh Boon Ung, *Supply and Demand Analysis for Capture and Storage of Anthropogenic Carbon Dioxide in the Central U.S.* (National Petroleum Council, Working Paper 2019), https://dualchallenge.npc.org/files/CCUS%20Topic%20Paper%201-Jan2020.pdf.

Figure 7. Map showing locations of coal and natural gas-fired power plants used in the Carbon Solutions study



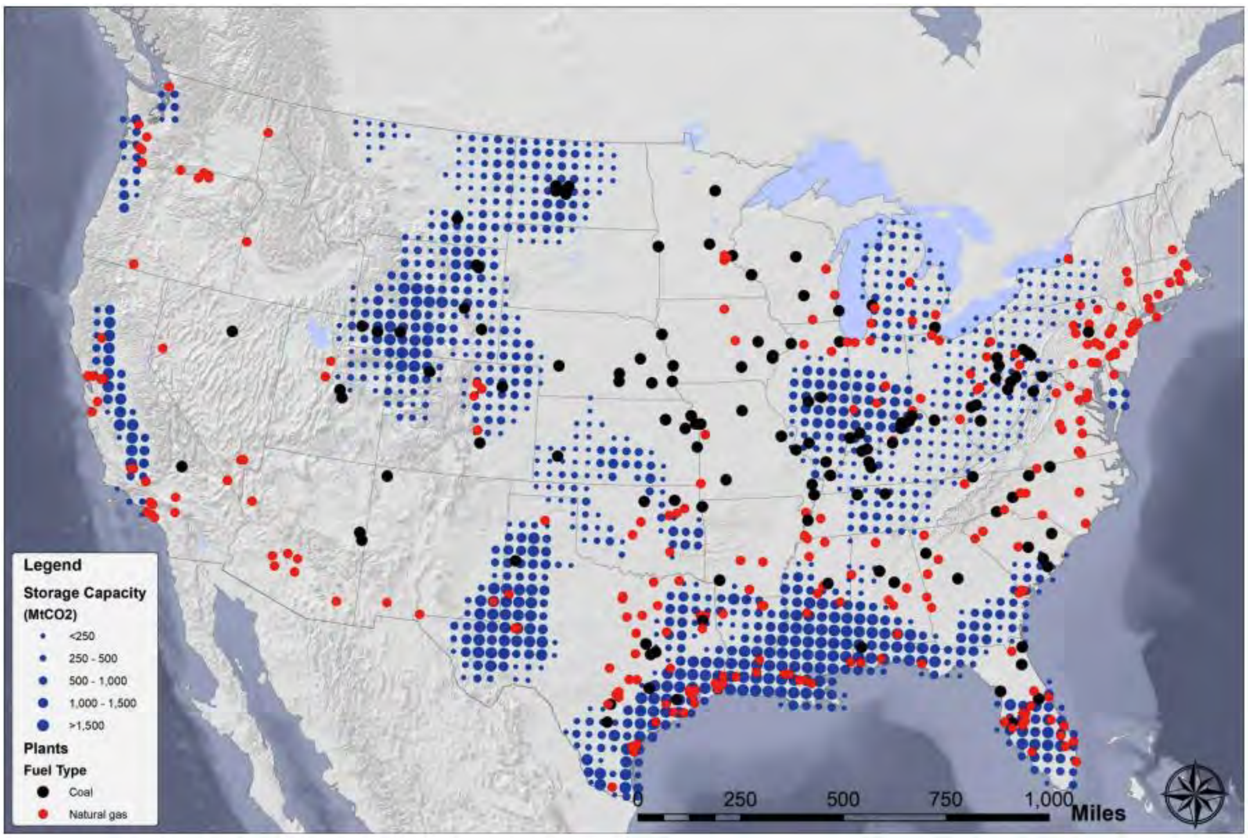
3. Transport

Carbon Solutions identified low-cost and optimized CO_2 pipeline routes for each modeled scenario using its CostMAP pro tool, which develops pipeline routes at multiple resolutions ranging from 30m to 720m grid cells. 720m grid cell resolution was used for this study. Baseline pipeline costs were generated using the latest version of the FECM/NETL CO_2 Transport Cost Model. These costs were updated to 2022 to align with the same dollar-year used for CO_2 capture costs. Average transport costs ranged from \$2.24 to \$8.04/ton CO_2 across the modeled buildout scenarios.

4. Storage

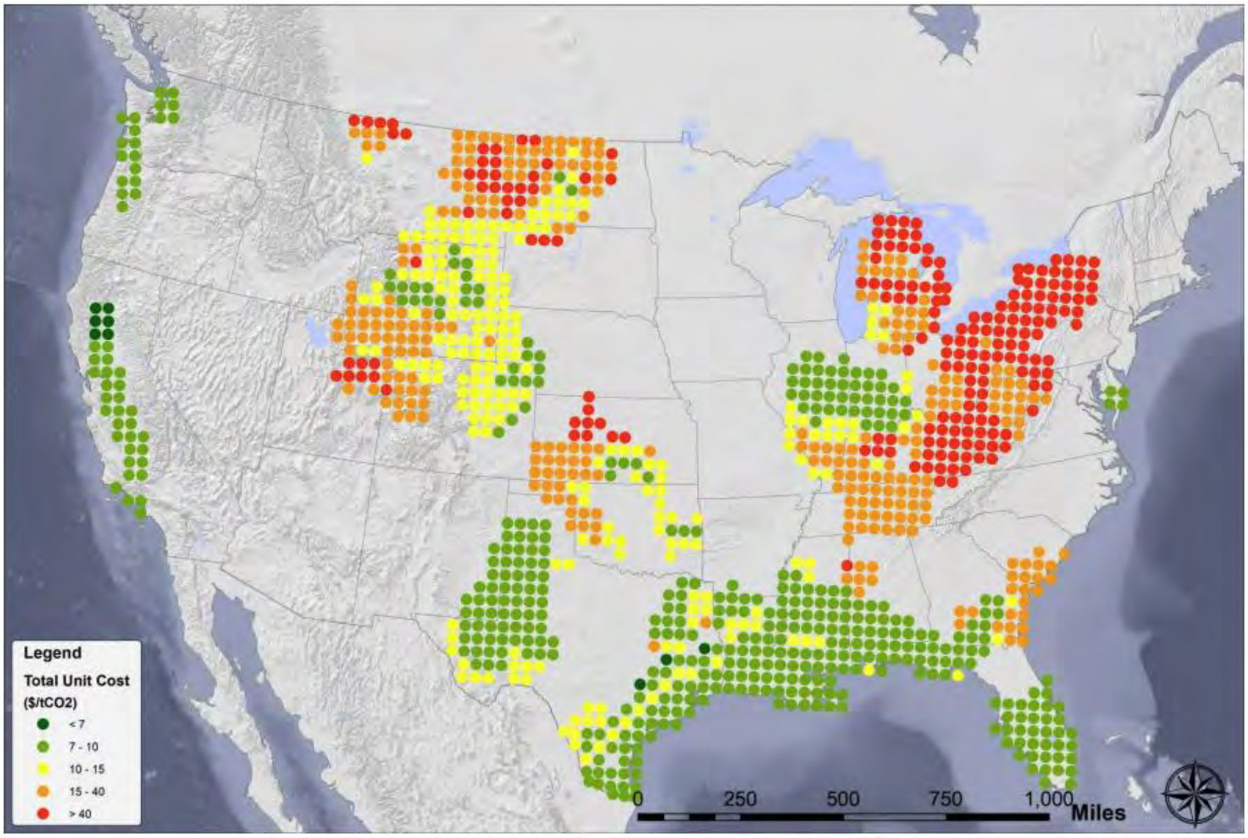
Carbon Solutions generated saline storage CO_2 estimates using its SCO_2T^{PRO} tool and database. This tool uses a dynamic injection approach to estimating effective storage capacities, which yields a more advanced estimate of storage potential than the static estimates generated by DOE's NATCARB Atlas. Storage sites were aggregated on a 50 km grid, avoiding urban areas, national parks, and other infeasible surface features. For each 50 km sink where multiple storage formations were present, the "best" reservoir in each stack was selected and used for the cost basis. Only onshore saline aquifers were considered for this study, though there is vast storage potential in offshore saline aquifers and in depleted oil and gas fields. The SCO_2T pro tool was also used to generate advanced storage costs estimates. This tool provides more accurate estimates of storage costs than methods that use volumetric storage estimation (e.g., FE/NETL CO_2 Saline Storage Cost Model) as volumetric approaches (as opposed to dynamic injection approach used in this study) often overestimate the number of required injection wells for a given scenario which leads to significantly inflated cost estimates.[509] Average storage costs estimates for this study ranged from $8.52 to $8.76/ton CO_2 across the modeled distributed storage buildout scenarios.

Figure 8. Map of U.S. saline storage capacity with locations of coal and natural gas-fired power plants, from Carbon Solutions study



[509] Jonathan D. Ogland-Hand et al., *Screening for Geologic Sequestration of CO_2: A Comparison Between SCO_2T^{PRO} and the FE/NETL CO_2 Saline Storage Cost Model*, 114 Int'l J. Greenhouse Gas Control 103557 (2022), https://www.sciencedirect.com/science/article/pii/S175058362100308X?via%3Dihub.

Figure 9. Map illustrating generalized unit costs of saline storage per ton of CO2 across the U.S., from Carbon Solutions study



5. Results

Optimized CCS buildout scenarios were modeled across a range of capture targets (200, 400, 600, 800, 1,000, and 1,044 $MtCO_2$/yr (representing the emissions from the full set of coal and gas plants modeled)). For each modeled scenario, outputs include:

- Target capture ($MtCO_2$/yr)
- Sources deployed
- Sinks deployed
- Pipeline network length (km)
- Total costs for capture, transport, and storage ($M/yr)
- Per metric ton costs for capture, transport, and storage ($/ton CO_2)

Total CCS buildout costs (capture, transport and storage) ranged from $79.22 to $86.92/ton CO_2 across the modeled buildout scenarios. These results suggest that CCS buildout for the bulks of the existing gas and coal fleets is economically viable and technically feasible considering various cost metrics including the current IRS Section 45Q tax credit incentive value of $85/ton

CO_2, the social cost of emitted carbon, and the cost of comparable pollution controls such as FGD. The full report can be found at Attachment 11.

Table 5: Summary outputs of national-scale CCS buildout modeling for coal and natural gas-fired power plants

Target ($MtCO_2$/yr)	Sources de-ployed	Sinks de-ployed	Hubs de-ployed	Network length (km)	Total costs ($M/yr)				Per tonne costs ($/$tCO_2$)			
					Total	Capture	Transport	Storage	Total	Capture	Transport	Storage
200	43	32	N/A	2,133	15,844	13,660	449	1,736	79.22	68.3	2.24	8.68
400	102	64	N/A	5,147	32,386	27,610	1,272	3,504	80.97	69.02	3.18	8.76
600	183	96	N/A	9,627	49,338	41,760	2,449	5,129	82.23	69.6	4.08	8.55
800	260	120	N/A	16,064	66,906	55,821	4,228	6,858	83.63	69.78	5.28	8.57
1000	389	142	N/A	27,814	85,989	70,262	7,148	8,580	85.99	70.26	7.15	8.58
1044	429	146	N/A	32,550	90,743	73,462	8,391	8,890	86.92	70.37	8.04	8.52

Figure 10. Infrastructure and costs with a capture target of 200 MtCO2/yr, from Carbon Solutions study

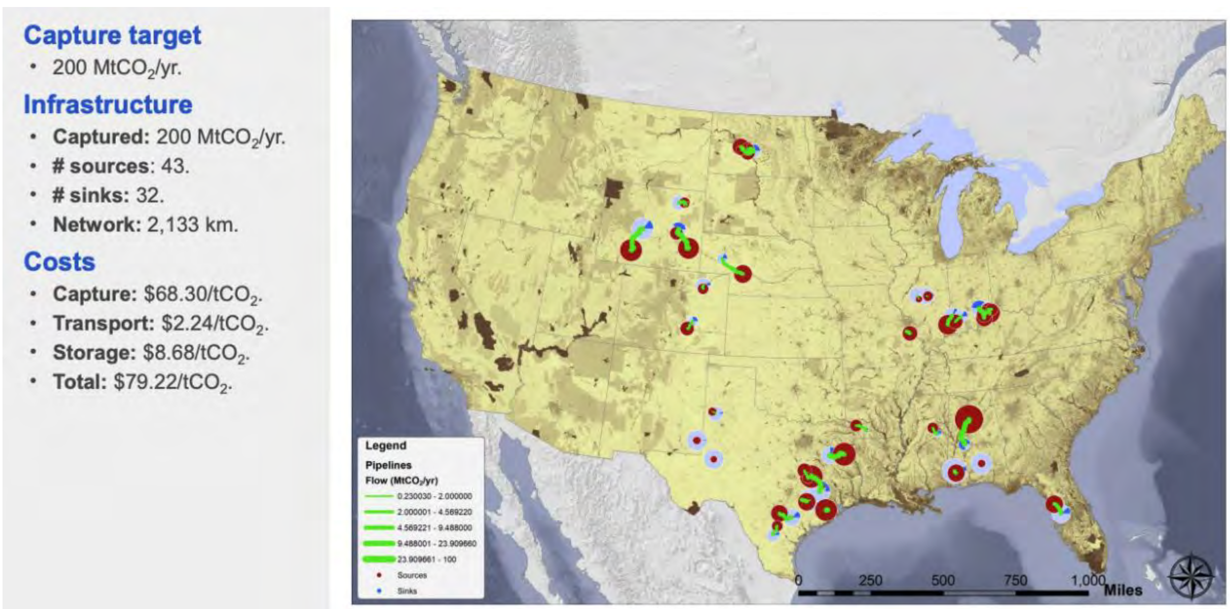


Figure 11. Infrastructure and costs with a capture target of 400 MtCO2/yr, from Carbon Solutions study

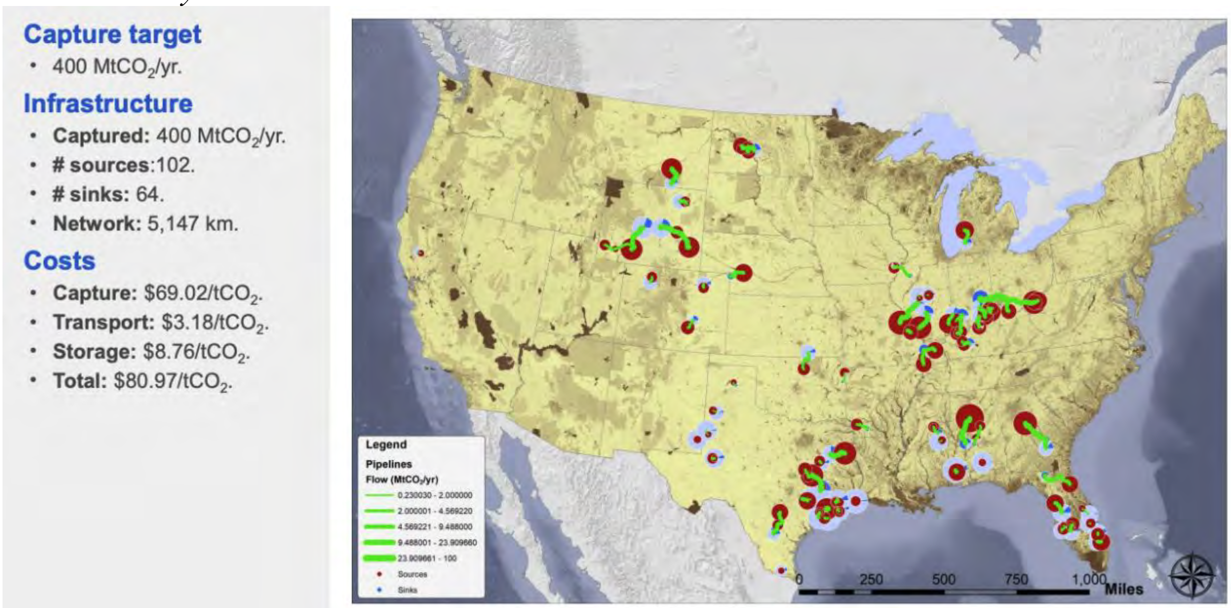


Figure 12. Infrastructure and costs with a capture target of 600 MtCO2/yr, from Carbon Solutions study

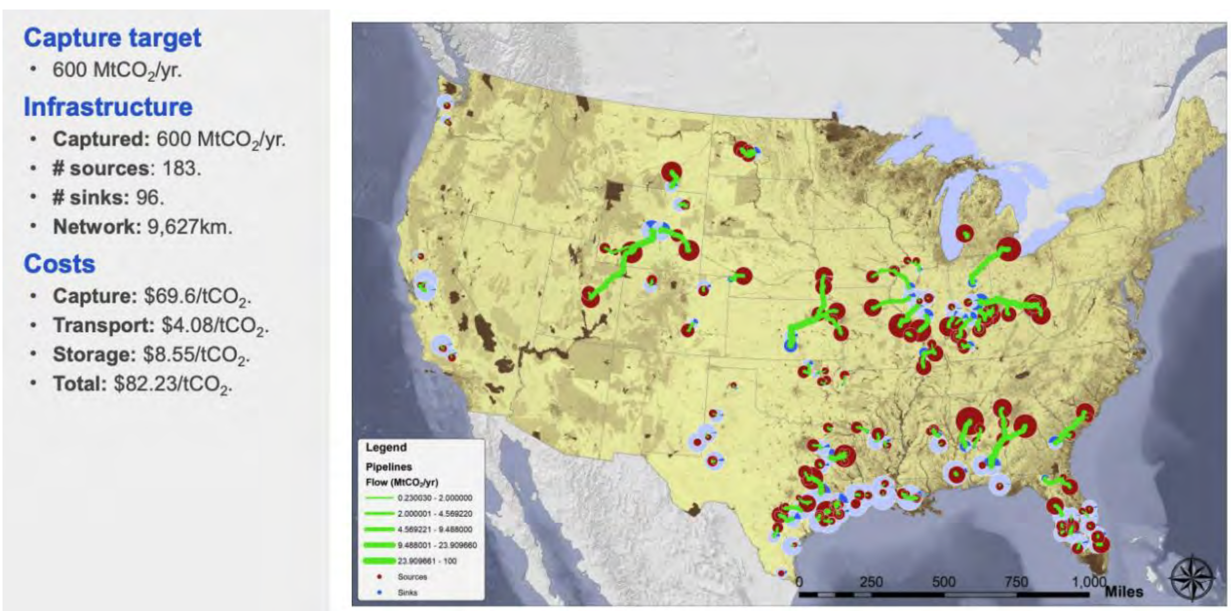


Figure 13. Infrastructure and costs with a capture target of 800 MtCO2/yr, from Carbon Solutions study

Capture target

- 800 $MtCO_2$/yr.

Infrastructure

- **Captured:** 800 $MtCO_2$/yr.
- **# sources**:260.
- **# sinks:** 120.
- **Network:** 16,064 km.

Costs

- **Capture:** \$69.78/tCO_2.
- **Transport:** \$5.28/tCO_2.
- **Storage:** \$8.57/tCO_2.
- **Total:** \$83.63/tCO_2.

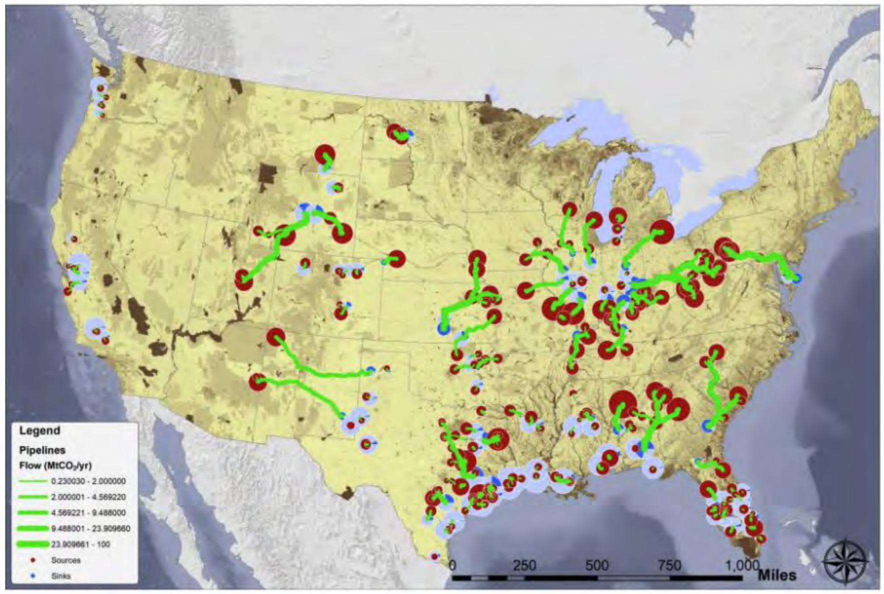


Figure 14. Infrastructure and costs with a capture target of 1,000 MtCO2/yr, from Carbon Solutions study

Capture target

- 1,000 $MtCO_2$/yr.

Infrastructure

- **Captured:** 1,000 $MtCO_2$/yr.
- **# sources**: 389.
- **# sinks:** 142.
- **Network:** 27,814 km.

Costs

- **Capture:** \$70.26/tCO_2.
- **Transport:** \$7.15/tCO_2.
- **Storage:** \$8.58/tCO_2.
- **Total:** \$85.99/tCO_2.

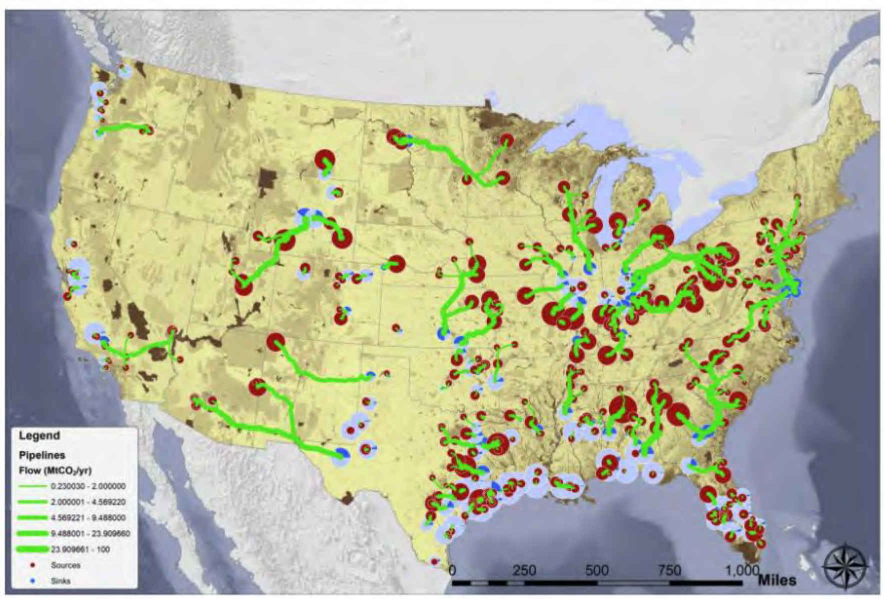
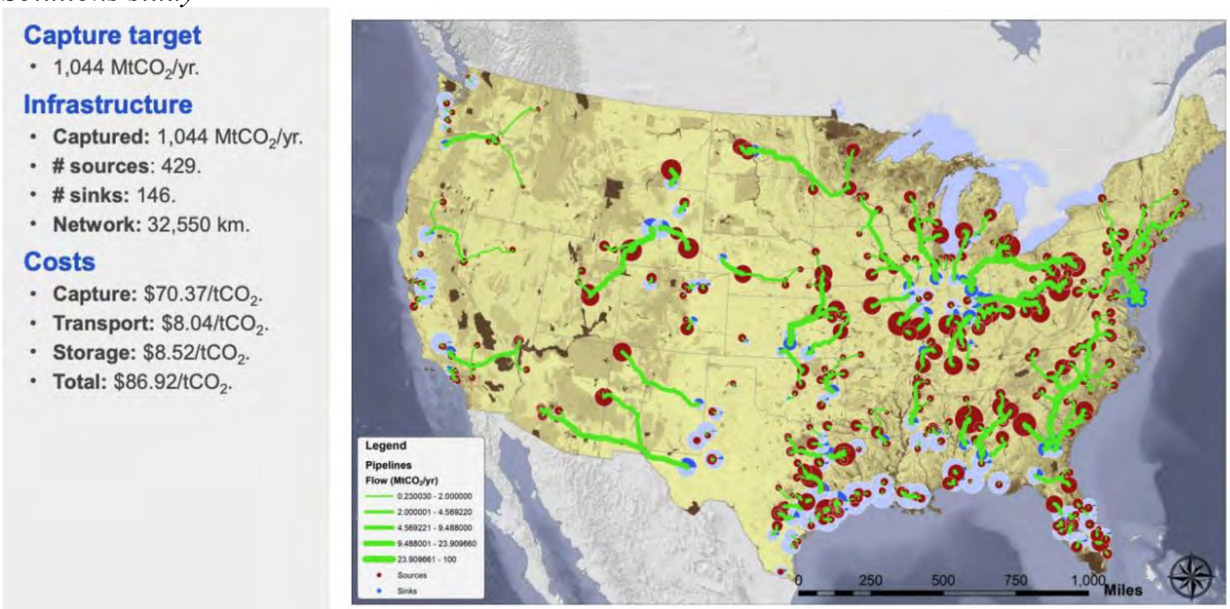


Figure 15. Infrastructure and costs with a capture target of 1,044 MtCO2/yr, from Carbon Solutions study



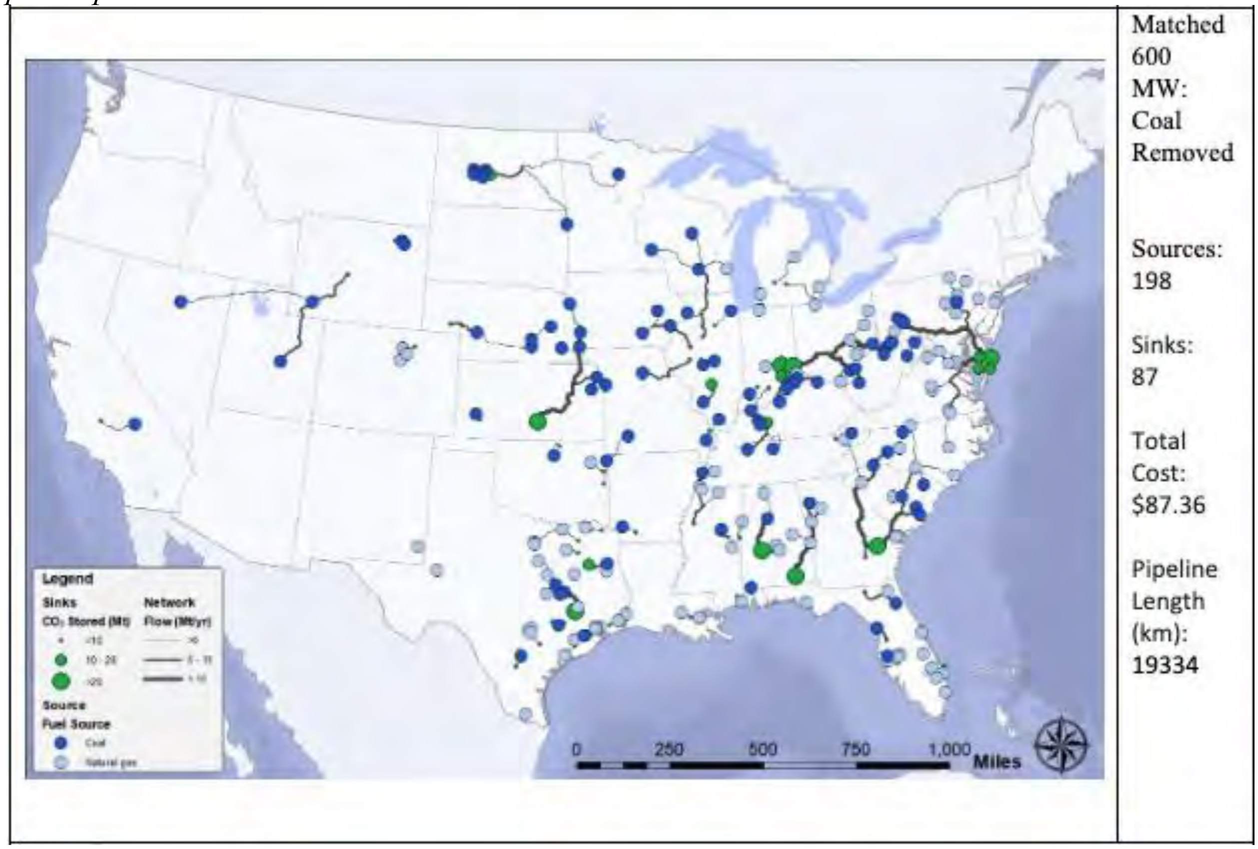
In addition to these modeled buildout scenarios that cover the bulk of the existing coal and natural gas-fired power plant fleet that does not have an announced retirement date prior to 2030, Commenters requested Carbon Solutions, LLC to perform an additional sensitivity model run that more accurately reflects plants that are covered in this proposal. Attachment 12. Below are the updated parameters considered for this model scenario:

- NGCC's: plants operating at or above 600 MW
- Coal: plants not set to retire by 2038
- Total # of plants: 198
- Annual CO_2 stored: 618 Mt

CCS buildout costs for this run totaled $87.36 per ton (averaged), which included 198 plants. Average costs by segment of value chain; capture ($69.93/ton), transport ($8.80/ton), storage ($8.63/ton). Total pipeline network length was 19,334 km, which is notably—41 percent—shorter than the previous scenarios that considered a larger number of plants (32,550 km). It is important to note that for this modeled scenario, we assume that every plant considered in this scenario chooses to comply with the standard by applying CCS and the results suggest that CCS buildout for all of these plants is still cost reasonable (average cost of $87.36/ton) when considering the IRS Section 45Q tax credit value of $85/ton.[510]

[510] Carbon Solutions, LLC, *Affected Fleet Sensitivity* (2023) [Attachment 12].

Figure 16. Infrastructure and costs associated with CCS at covered coal-fired and gas-fired power plants



E. Safety

1. Geologic Storage Is Governed by a Robust Existing Regulatory Framework

There is a robust existing regulatory framework that enables safe deployment of CCS. Geologic storage is regulated by the EPA under the Underground Injection Control Program (UIC) of the Safe Drinking Water Act. EPA's UIC program regulates construction, operation, permitting, and closure of injection wells that are used to store fluids in the subsurface. The principal goal of the UIC program is to protect underground sources of drinking water (USDWs) and the program currently permits six classes of injection wells.

EPA's UIC program establishes several classes of injection wells, each subject to different standards. Permanent storage of carbon dioxide is regulated under the Class VI wells program. Class VI wells have extensive requirements to ensure that geologic storage of CO_2 is safe and secure. The Class VI well process starts with stringent permitting requirements designed for ensuring the safety and permanence of CO_2 injection. These permitting requirements ensure that Class VI wells used for storage of CO_2 are appropriately sited, constructed, tested, monitored, and funded.[511] Class VI requirements also ensure that such wells are properly closed and that

[511] *See* 40 C.F.R. §§ 146.81-.95.

storage sites are appropriately characterized. Below is a more detailed breakdown of the specific criteria for Class VI wells:

- Extensive site characterization requirements, including reservoir modeling that accounts for the physical and chemical properties of the injected CO_2 and identification of a confining zone, or "caprock," directly above the injection zone that acts as a barrier to upward fluid movement.[512]
- Injection well construction requirements for the use of materials that are compatible with and can withstand contact with carbon dioxide and subsurface conditions over the life of a geologic storage project.[513]
- Injection well operational requirements, including injection pressure limitations and use of down-hole shut-off systems to ensure that injection of CO_2 does not endanger underground sources of drinking water.[514]
- Comprehensive monitoring requirements that address all aspects of well integrity, CO_2 injection and storage, and ground water quality during injection operations and throughout the 50-year default post-injection site care period. This period can be shortened if operators demonstrate that there is substantial evidence, based on site-specific data, that the geologic storage project does not pose a risk of endangerment to USDWs.[515]
- Financial responsibility requirements assuring the availability of funds for the life of a geologic storage project sufficient to cover the cost of corrective action, injection well plugging, post-injection site care and site closure, and emergency and remedial response.[516]
- Reporting and recordkeeping requirements that provide project-specific information to continually evaluate Class VI operations and confirm USDW protection.[517]

Under EPA's UIC Class VI program, developers that have received a Class VI permit are required to report under subpart RR of the Greenhouse Gas Reporting Program (GHGRP).[518] The two programs work together to ensure secure, permanent storage of CO_2 and provide monitoring and reporting that identifies and addresses any potential leakage risks and provides public transparency. Class VI permit holders are required to submit annual reports to EPA under subpart RR that include amounts of carbon dioxide that is geologically stored based on mass-balance calculations and monitoring activities.[519] Under subpart RR, facilities are required to develop and implement a monitoring, reporting, and verification (MRV) plan that is approved by EPA.[520] An overview of the required contents of an MRV plan is provided below:

- Delineation of the maximum monitoring area and the Area of Review (AoR) which is the are where pressure perturbations from the injected carbon dioxide are great enough to

[512] *See id.* § 146.83.
[513] *See id.* § 146.86.
[514] *See id.* § 146.88.
[515] *See id.* § 146.90.
[516] *See id.* § 146.85.
[517] *See id.* § 146.91.
[518] *See id.* §§ 98.440-.449.
[519] *See id.* § 98.446.
[520] *See id.* § 98.448.

potentially displace fluids into lowermost USDWs through any potential leakage pathways (e.g., existing wellbores);

- Identification of potential leakage pathways within the AoR (wells, faults, fractures, and caprock competency);
- A detailed strategy for detecting potential leakage of injected carbon dioxide;
- A detailed strategy for establishing a baseline of pre-injection conditions for monitoring of injected carbon dioxide;
- Description of site-specific variables for calculating mass-balance of injected carbon dioxide;
- Well information, including identification numbers; and
- Proposed date to commence data collection for calculating stored carbon dioxide.

The Class VI regulation provides an important, robust environmental backstop that ensures all geologic storage projects are conducted safely and securely.

2. Precedents for Safety of Geologic Storage

Geologic storage carries minimal risk of leakage in well-characterized and well-maintained storage sites. Subsurface geologic formations are capable of retaining fluids, for instance (e.g., hydrocarbons and even naturally occurring CO_2), in the subsurface over geologic time (i.e., up to hundreds of millions of years). The existence of oil and natural gas reserves and naturally occurring CO_2 accumulations in the subsurface demonstrate this ability. According to the IPCC, well-selected geologic storage sites will likely exceed 99 percent retention of injected CO_2 over 1,000 years with "high confidence" that CO_2 can be permanently isolated from the atmosphere.[521]

Carbon dioxide has been injected and stored in deep geologic formations at the commercial scale since the 1970s, with an excellent track record of safety. During this time, over 1 billion tons of CO_2 have been injected into deep geologic formations in the United States alone. The majority of CO_2 injected to date has been via EPA Class II injection wells for the purpose of enhanced oil recovery. The Gulf Coast Carbon Center conducted a major research project in the Scurry Area Canyon Reef Operators (SACROC) oilfield in the Permian Basin focusing on the potential impacts of CO_2 EOR on shallow subsurface aquifers. While the SACROC oil field has seen over 175 million tons of CO_2 injected since 1972, the study found that shallow drinking water aquifers located in geologic layers above the SACROC oil field have not been impacted by injection of CO_2 into these deeper formations.[522] Importantly, Class II injection wells have markedly fewer requirements than Class VI injection wells for ensuring safety and security of injected CO_2. The safe track record of CO_2 injection via Class II wells provides assurance that future injection operations can also be carried out without harm to underground drinking water supplies, much less harm to public health. In fact, Class VI wells are anticipated to carry even less risk than Class II wells due to the additional protections required of Class VI wells (e.g., more extensive

[521] IPCC, *Carbon Dioxide Capture and Storage* 14 (2005) (special report prepared by IPCC Working Group III), https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_wholereport-1.pdf; IPCC, *Climate Change 2022: Mitigation of Climate Change Summary for Policymakers*, https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_SummaryForPolicymakers.pdf.
[522] *See generally* Gulf Coast Carbon Ctr., *SACROC Research Project*, https://www.beg.utexas.edu/gccc/research/sacroc.

site characterization requirements, injection well construction and operating requirements, area of review delineation and plume modeling requirements, extensive monitoring requirements, etc.).

F. Concerns About Permitting Delays

In October 2022 EPA submitted a report to Congress on Class VI permitting.[523] A robust and comprehensive permit application and review process is fundamental, but EPA agreed that the process can be streamlined and that it needs to speed up the process. As described below, EPA has recently, however, demonstrated its ability to permit Class VI wells in a reasonable timeframe by issuing its intent to permit two Class VI wells for Wabash Carbon Services, and expects to be able to maintain its anticipated two-year review timeline.

The 2018 and 2022 passage of enhancements to IRS Section 45Q tax credit, along with IIJA and IRA investments related to CCS development and deployment, have spurred significant commercial interest in CCS projects. There are currently 109 Class VI permit applications submitted to EPA and currently pending review. There are currently only fourteen Class VI well permits that have been issued in the U.S., of which six were permitted by EPA region 5 (only two of which are currently active) and eight permitted by the North Dakota Industrial Commission.

The most recent Class VI permit issued by EPA was in 2014 and the first Class VI permits took approximately 6 years to be issued. EPA has attracted scrutiny over the long review period for these initial Class VI permits. But EPA now anticipates that prospective owners or operators submitting complete Class VI applications will be issued permits in approximately two years.[524] In its 2022 report to Congress on Class VI permitting, EPA indicated that, while there is limited data on Class VI permitting timeframes, processing times for other UIC well classes offer a valid metric of comparison. For example, Class I wells are similar to Class VI in terms of regulatory structure, including the amount of site-specific data that is required as part of the permit application. EPA states that the processing time for Class I permits has typically been less than two years, and since 2019, EPA has issued 25 new Class I permits. This provides precedent that EPA has the ability to permit Class VI wells in a timely manner (i.e., approximately two years).

EPA has recently developed a suite of tools and strategies for permitting Class VI wells. It includes early engagement; improvements to its geologic sequestration data tool in order to streamline the application process; templates; samples; application guidance; training for regulators; mapping tools; and tools for UIC permit writers to standardize and expedite the process. NETL has also recently launched a new data portal that provides information needed to accelerate the process of completing a Class VI permit.[525] Operators can use the new database to query and download relevant spatial data for the entire U.S. and visualize subsurface data. These

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[523] EPA, *EPA Report to Congress: Class VI Permitting* (2022), https://www.epa.gov/system/files/documents/2022-11/EPA%20Class%20VI%20Permitting%20Report%20to%20Congress.pdf.
[524] *Id.*
[525] Carbon Capture Journal, *NETL data portal to aid completion of permit applications for carbon storage* (Apr. 13, 2023), https://www.carboncapturejournal.com/news/netl-data-portal-to-aid-completion-of-permit-applications-for-carbon-storage/5504.aspx?Category=all.

tools will help both prospective applicants and EPA to accelerate permitting timelines. EPA is also encouraging and supporting states with applying for Class VI primacy.

Additional funding support for EPA Class VI permitting is included in the Bipartisan Infrastructure Law, totaling $25 million between FY22 and FY26 to specifically address challenges around permitting timelines and ensure that EPA has the appropriate resources to keep up with the growing influx of Class VI permit applications. An additional $50 million is available between FY22 and FY26 to support state primacy for states to administer EPA's UIC program. Currently, ND and WY have state primacy for Class VI well permitting, LA's primacy application is currently being evaluated by EPA, and WV, TX, and AZ are engaged in pre-application activities.

EPA recently announced its intent to issue two Class VI permits to Wabash Carbon Services for its planned CCS project in Indiana. This marks the first Class VI wells announcement by EPA since 2014 and demonstrates that EPA is capable of permitting Class VI wells in a timely manner and that their review timelines have shortened since the last permitted well.

G. Storage Projects Underway and Being Considered

There were two saline storage projects in operation (i.e., injecting CO_2) and 142 EOR projects injecting CO_2 as of year-end 2020 in the U.S. Following the 2018 enhancements to IRS Section 45Q tax credit, there was a significant surge in commercial interest in CCS with over 100 commercial projects announced since 2018.[526] Of these announced projects, there are numerous large-scale storage projects underway that have significant storage capacities and are intended to be used as storage hubs for a variety of industries. Of note, these ten projects have a total planned storage capacity in the billions of tons:

- *Bayou Bend CCS Hub*
  - Planned capacity: >1 Gt
  - Location: TX
- *Gulf Coast Sequestration Hub*
  - Planned capacity: 300 Mt
  - Location: LA
- *Denbury Donaldsonville Hub*
  - Planned capacity: 300 Mt
- *Livingston Parish Sequestration Hub*
  - Planned capacity: 6 Mt/year
  - Location: LA
- *Central Louisiana Regional Carbon Storage Hub*
  - Planned capacity: 1 Gt
  - LA
- *Houston Ship Channel CCS Innovation Zone*
  - Planned capacity: 100 Mt
  - Location: TX
- *Carbon Terravault I*

[526] CATF, *US Carbon Capture Activity and Project Map*, https://www.catf.us/ccsmapus/.

- Planned capacity: 40 Mt
    - Location: CA
- *Carbon Terravault II & III*
    - Planned capacity: 80 Mt
    - Location: CA
- *Navigator CO_2 Hub*
    - Planned capacity: 10 Mt/year
    - Location: IL
- *Wolf Carbon Solutions Hub*
    - Planned capacity: 12 Mt/year
    - Location: IL

III. Pipelines

CO_2 pipelines are an essential transport component of the CCS capture, transport, and storage value chain. In comparison to the 1.89 million mile U.S. oil and gas pipeline network,[527] there are currently 5,000 miles of pipelines carrying CO_2, primarily from natural CO_2 sources to oil fields where the CO_2 is used for enhanced oil recovery.[528] While the U.S. has a strong track record for operating CO_2 pipelines for the past 50 years, there are considerations that must be taken into account, including permitting concerns, cost of transport, and safety standards.

From 2001 to 2021, the fastest pace of pipeline expansion in the U.S. took place from 2001 to 2006 where the total U.S. oil and gas pipeline mileage increased from 1.57 million miles to 1.68 million miles (an average of nearly 21,000 miles per year). Gas transmission pipeline mileage increased from 289,994 miles to 300,324 miles during the same time period (an average of just over 2,000 miles per year).[529] In comparison, the mileage of CO_2 pipelines required to comply with the proposed standards is likely to be far smaller than these historic annual pipeline construction rates. The Carbon Solutions Report described earlier showed a total maximum CO_2 pipeline need of 12,013 miles to capture all of the CO_2 from the portion of the fleet Commenters propose subjecting to a CCS-based standard. This maximum buildout scenario represents just over half of the average buildout associated with *one year* during the natural gas boom. Studies suggest that the U.S. will need 30,000 to 66,000 miles of CO_2 pipelines by 2050 in order to meet net-zero targets.[530] Even this economy-wide decarbonization goal only requires an average of 2,444 miles annually from 2023.

The IRA and IIJA include provisions that support CO_2 pipeline development, including a Carbon Dioxide Transportation Infrastructure Finance and Innovation Program (CIFIA) for CO_2

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[527] BTS, *supra* note 349.
[528] Cong. Rsch. Serv. (CRS), *Carbon Dioxide (CO_2) Pipeline Development: Federal Initiatives* (2023) [hereinafter CRS, *CO_2 Pipeline Development*], https://crsreports.congress.gov/product/pdf/IN/IN12169#:~:text=Approximately%205%2C000%20miles%20of%20pipeline,goals%20for%20greenhouse%20gas%20reduction.
[529] BTS, *supra* note 349.
[530] Eric Larson et al., Princeton Univ., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts* (2021), https://netzeroamerica.princeton.edu/img/Princeton%20NZA%20FINAL%20REPORT%20SUMMARY%20(29Oct2021).pdf; https://www.betterenergy.org/wp-content/uploads/2020/06/GPI_RegionalCO2Whitepaper.pdf.

pipelines. This IIJA (Section 40304) program provides $2.1 billion for low-interest loans and grants for CO_2 transportation, including pipelines, with a 2024 budget request of $308 million in direct loan subsidies and $25 million in grants.[531] Section 40303 of the IIJA also gives DOE the authority to include support for CO_2 transport infrastructure FEED studies, and in May 2023, DOE announced $9 million in funding for three CO_2 pipeline network FEED studies in Wyoming, Louisiana, and Texas.[532] The IRA (Section 40314) established the Regional Clean Hydrogen Hubs program, which will provide funding to support six to 10 hubs. It is anticipated that several of these hubs will include CCS, and may require pipeline infrastructure.

Developers such as Summit Carbon Solutions, Navigator CO_2 Ventures, and Wolf Carbon Solutions are requesting permits to develop CO_2 pipeline transport networks in the upper Midwest, and have begun engaging stakeholders. Meanwhile, Wood is delivering concept and FEED studies for nearly 2,000 miles of onshore low-carbon pipelines in North America.[533]

While the track record for CO_2 pipeline safety in the U.S. is very strong (500 millions of metric tons moved through 5,000 miles of CO_2 pipelines, with no fatalities associated with regulated pipelines over the past 20 years),[534] a recent unacceptable incident in Satartia, Mississippi has focused attention on pipeline safety. In certain atmospheric conditions (lack of wind and sun) like those present when the Satartia rupture occurred, CO_2 can displace oxygen, resulting in adverse health effects (including suffocation). Pipeline CO_2 that is mined can also contain associated hydrogen sulfide.[535] As with other types of pipeline transport such as oil and gas, CO_2 pipelines must be well designed and continuously monitored in order to protect public safety.

States have primary siting authority over CO_2 pipelines and also set safety standards for intra-state pipelines. For pipelines that cross interstate lines, the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) sets safety standards governing CO_2 pipeline construction, maintenance, and operation.[536] PHMSA currently applies safety requirements to CO_2 pipelines similar to those for pipelines carrying hazardous liquids such as crude oil and anhydrous ammonia.[537] Since the Satartia incident, PHMSA has taken several steps concerning CO_2 pipeline safety. The first was to require all operators to improve their evaluation of geohazards such as the land movement that caused the Satartia rupture. It also conducted a failure investigation of the Satartia incident, imposed fines on the operator and is conducting additional research to improve CO_2 pipeline management. PHMSA has also indicated that it plans to update its safety standards, with an expected proposal in 2024. The new standards should be completed well in advance of new pipeline construction needed to enable compliance with the proposed power plant standards.

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[531] CRS, *CO_2 Pipeline Development*, *supra* note 528.
[532] *Id*.
[533] Press Release, Wood PLC, "Wood Delivers 2,000 miles of low carbon pipeline projects in North America," (Aug. 3, 2023) https://www.woodplc.com/news/latest-press-releases/2023/wood-delivers-2000-miles-of-low-carbon-pipeline-projects-in-north-america.
[534] CRS, *Carbon Dioxide Pipelines: Safety Issues* (2022) [hereinafter CRS, *CO_2 Pipelines: Safety Issues*], https://crsreports.congress.gov/product/pdf/IN/IN11944.
[535] *Id.*
[536] CRS, *CO_2 Pipeline Development*, *supra* note 528.
[537] CRS, *CO_2 Pipelines: Safety Issues*, *supra* note 534.

In addition to the work that PHMSA is undertaking, the National Energy Technology Laboratory (NETL) has developed a CO_2 Pipeline Route Planning Database to help guide pipeline routing decisions and increase transportation safety. In developing this database, NETL has identified technical gaps, prioritized research needs, and developed tools to optimize CO_2 pipeline expansion in a way that is safe, sustainable, and reliable.[538]

IV. Costs of Carbon Capture and Sequestration

The costs of CCS on power plants depend upon many factors, including the concentration of CO_2 in the flue gas, other pollutants that must be treated to protect the amine used to capture CO_2, capacity factor, plant size, the amortization period, retrofit costs as opposed to including CCS as part of a new plant, and the availability of tax credits or other policies to offset costs. Commenters' recommendations in the Sec. VI focuses on CCS-based standards for those portions of the fleet that are cost reasonable. This section sets forth more detail on the costs of CCS depending on several variables and informs those recommendations.

NETL has developed detailed and transparent costs for CCS on power plants, including recent updates to fossil baseline reports and retrofit studies that include the latest vendor quotes for carbon capture and other updated data. EPA properly relies on these reports to develop the cost and performance basis of the proposal. These reports include:

New Coal and New Gas with CCS

- Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity[539]

Coal Retrofits with CCS

- Eliminating the Derate of Carbon Capture Retrofits (Revision 2)[540]
- Pulverized Coal Carbon Capture Retrofit Database[541]

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[538] *NETL develops pipeline route planning database*, Carbon Capture J. (Jun. 4, 2023), https://www.carboncapturejournal.com/news/netl-develops-pipeline-route-planning-database/5583.aspx?Category=all

[539] NETL, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (Oct. 19, 2022), https://www.netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf (update for new plants that came out on Oct. 19, 2022).

[540] NETL, *Eliminating the Derate of Carbon Capture Retrofits* (Mar. 31, 2023), https://www.osti.gov/biblio/1968037.

[541] NETL, *Pulverized Coal CO_2 Capture Retrofit Database* (Mar. 30, 2023) (spreadsheet allows users to apply the findings from the report above to a fleet of plants), https://www.netl.doe.gov/energy-analysis/details?id=e7e822ff-18ac-4bc6-a052-0be3521b8789.

Natural Gas Retrofits with CCS

- Cost and Performance of Retrofitting NGCC Units for Carbon Capture (Revision 3)[542]
- Natural Gas Combined Cycle CO_2 Capture Retrofit Database[543]

A. Costs of Carbon Capture for Gas-Fired Versus Coal-Fired Power Plants

Two attributes highlighted here strongly influence the cost difference between coal and gas plants CCS applications: 1) CO_2 concentrations in flue gas and 2) Pretreatment costs to prepare flue gas for entry into the capture system.

Flue gas concentrations of CO_2 in NGCC plants are about 3 percent compared to 12 percent for coal plants. This difference accounts for much of the cost difference between CCS applications on the two plants. Also, coal plant applications of CCS require more pretreatment steps for the flue gas to ensure that harmful pollutants such as PM, sulfates, and NO_2 do not form heat-stable salts with the amine or contribute to other degradation products that harm the capture system.

Because there is less CO_2 emitted per MWh from a gas plant relative to a coal plant, the cost of CCS on a gas plant is lower than a coal plant on an LCOE basis measured in $/MWh. However, the situation is reversed when measuring costs based on $/ton of CO_2 avoided. The cost per ton of CO_2 avoided with CCS on coal plants is less than on gas plants because the costs are spread over a larger quantity of CO_2 captured. The table below summarizes NETL findings from new coal and gas plants with 90 percent capture.[544]

Table 6. LCOE and Cost of CO2 Avoided for Coal and Gas EGUs[545]

	LCOE ($/MWh) (incl. T&S)	Cost of CO2 Avoided (incl. T&S), $/ton
Supercritical pulverized coal at 90% capture (SC PC: B12B.90 (12)	107.3	63.0
State-of-the-art 2017 F-Class combustion turbine NGCC at 90% capture (B31B.90 (14)	67.9	80.8

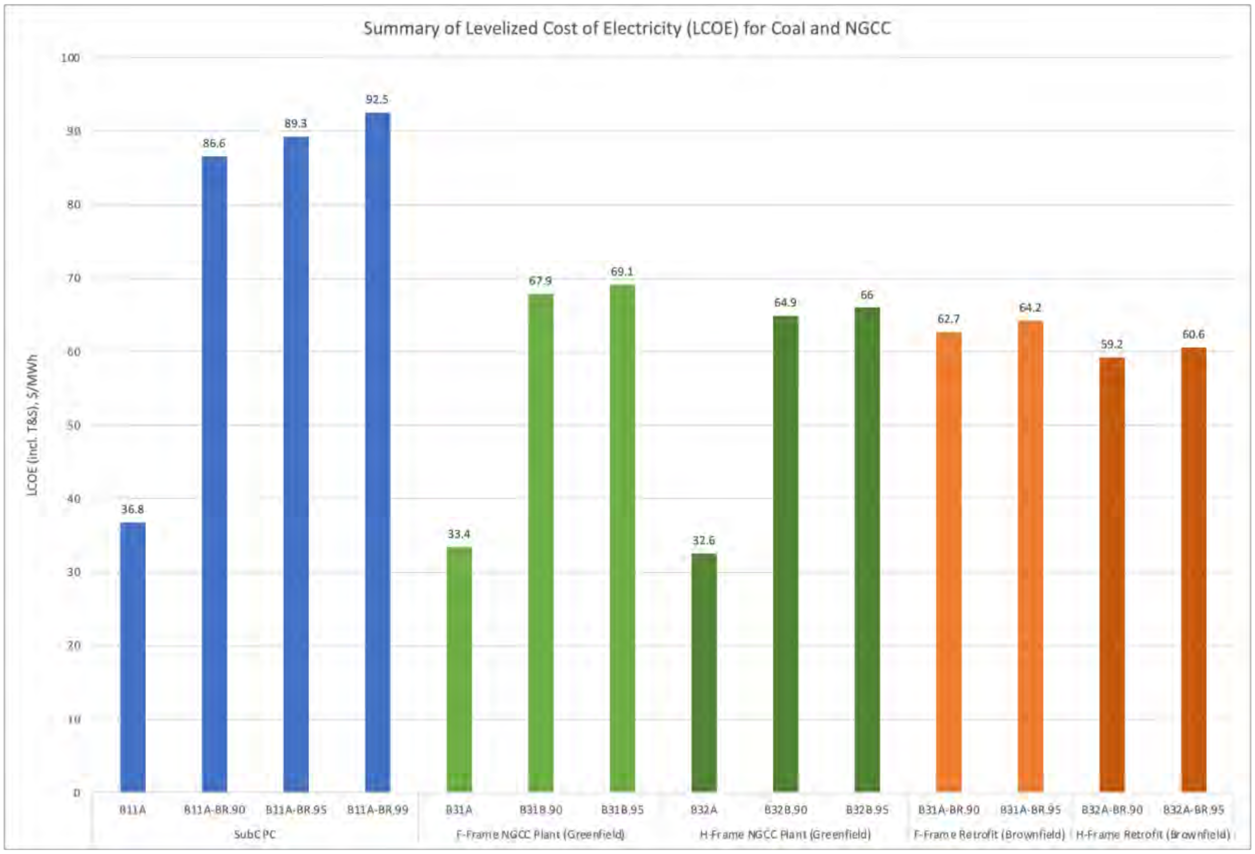
Assumes 30-year payback period.

While 90 percent capture is often described in studies, as described above, there is no technical barrier to achieving higher capture rates. The figure below summarizes NETL estimates for LCOE for retrofitting subcritical coal plants, new NGCC-CCS plants, and CCS retrofits on

[542] NETL, *Cost and Performance of Retrofitting NGCC Units for Carbon Capture (Revision 3)*, *supra* note 299 (This reports adapts the October 22 report on new gas plant CCS costs to account for the additional costs of retrofits.).
[543] NETL, *Natural Gas Combined Cycle CO_2 Capture Retrofit Database* (Mar. 16, 2023) (This spreadsheet adapts the report above to apply the findings to a fleet of gas plants), https://www.osti.gov/biblio/1962372.
[544] NETL, *Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, *supra* note 539.
[545] *Id.*

NGCC plants.[546] The cost of capture for coal plant retrofits ranges between around 86 \$/MWh to 92 \$/MWh. For new NGCC plants with CCS and retrofits of existing gas plants, the LCOE range between 59 and 66 \$/MWh.

Figure 17. LCOE of CCS on new and retrofitted coal-fired and gas-fired power plants[547]



Notes for figure:

- In order to account for the higher costs of a retrofit CCS application compared to the cost of including CCS as part of a new build, NETL applies a retrofit difficulty factor to the capital costs of CCS retrofits by multiplying the capital costs of an equivalent greenfield site by 1.09.
- The uncontrolled coal and gas plants are assumed to be fully paid off and LCOE excludes capital costs.
- LCOE is calculated on a 30-year plant life.

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[546] For data on NGCC plants, see NETL, *Cost and Performance of Retrofitting NGCC Units for Carbon Capture (Rev. 3)*, *supra* note 299. For data on coal retrofit plants, see NETL, *Eliminating the Derate of Carbon Capture Retrofits (Rev. 2)*, *supra* note 540.

[547] Sources cited *supra* note 546.

Table 7: NETL Case Specifications[548]

Case	Technology		Efficiency (% HHV)	2xGT (MWe)	ST (MWe)[A]	Gross (MWe)	Aux (MWe)	Net (MWe)
1 Subcritical Pulverized Coal	B11A	w/o CO_2 capture	38.6	N/A	N/A	688	38	650
	B11A-BR.90	w/90% CO_2 capture retrofit	29.4	N/A	N/A	588	93	495
	B11A-BR.95	w/95% CO_2 capture retrofit	28.9	N/A	N/A	584	96	488
	B11A-BR.99	w/99% $C0_2$ capture retrofit	28.4	N/A	N/A	578	99	479
2 SOA Based on F-Frame	B31A	w/o CO_2 capture	53.6	477	263	740	14	727
	B31B.90	w/90% CO_2 capture	47.6	477	215	692	47	645
	B31B.95	w/95% CO_2 capture	47.3	477	212	690	49	640
	B31A-BR.90	w/90% CO_2 capture retrofit	47.3	477	211	688	47	641
	B31A-BR.95	w/95% CO_2 capture retrofit	46.9	477	208	685	49	636
3 SOA Based on H-Frame	B32A	w/o CO_2 capture	55.1	686	324	1,009	17	992
	B32B.90	w/90% CO_2 capture	49.0	686	260	945	62	883
	B32B.95	w/95% CO_2 capture	48.7	686	256	942	65	877
	B32A-BR.90	w/90% CO_2 capture retrofit	48.7	686	255	940	62	878
	B32A-BR.95	w/95% CO_2 capture retrofit	48.4	686	251	936	65	872

NETL cost estimates for the avoided cost of capture for new and retrofit NGCC is shown below assuming a 30-year plant life.[549]

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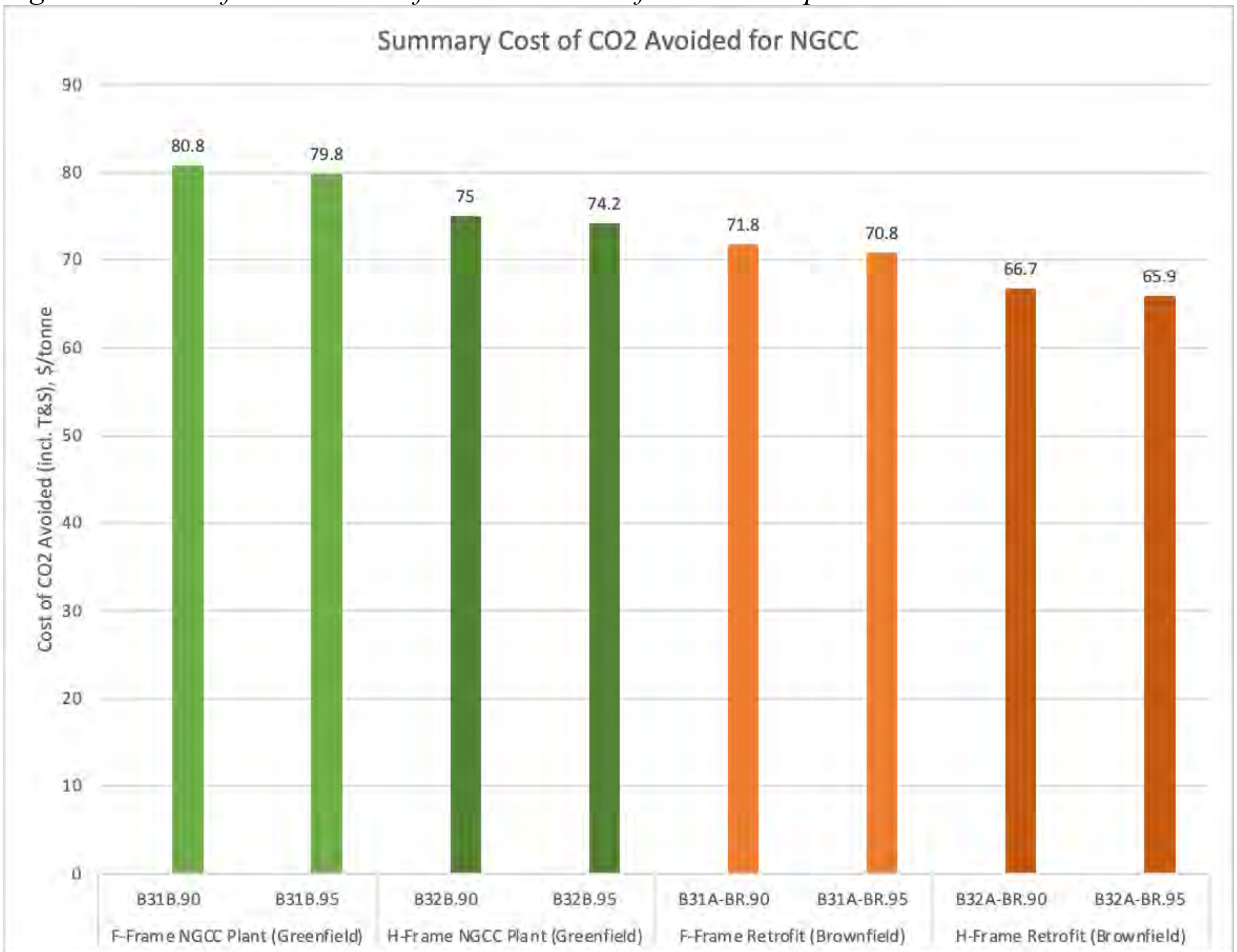
[548] *Id.*
[549] NETL, *Cost and Performance of Retrofitting NGCC Units for Carbon Capture (Rev. 3)*, *supra* note 299.

Figure 18. Cost of CO2 avoided for new and retrofitted NGCC plants[550]



B. Costs Depend on Amortization Time

The costs shown in the previous section assume a 30-year plant life. For projects that utilize 45Q credits, a 12-year project life may be a more appropriate basis to calculate LCOE because that period matches the time a project can claim the tax credits.

Shortening the amortization periods increases the cost of capture of a project as shown in the figure below.[551]

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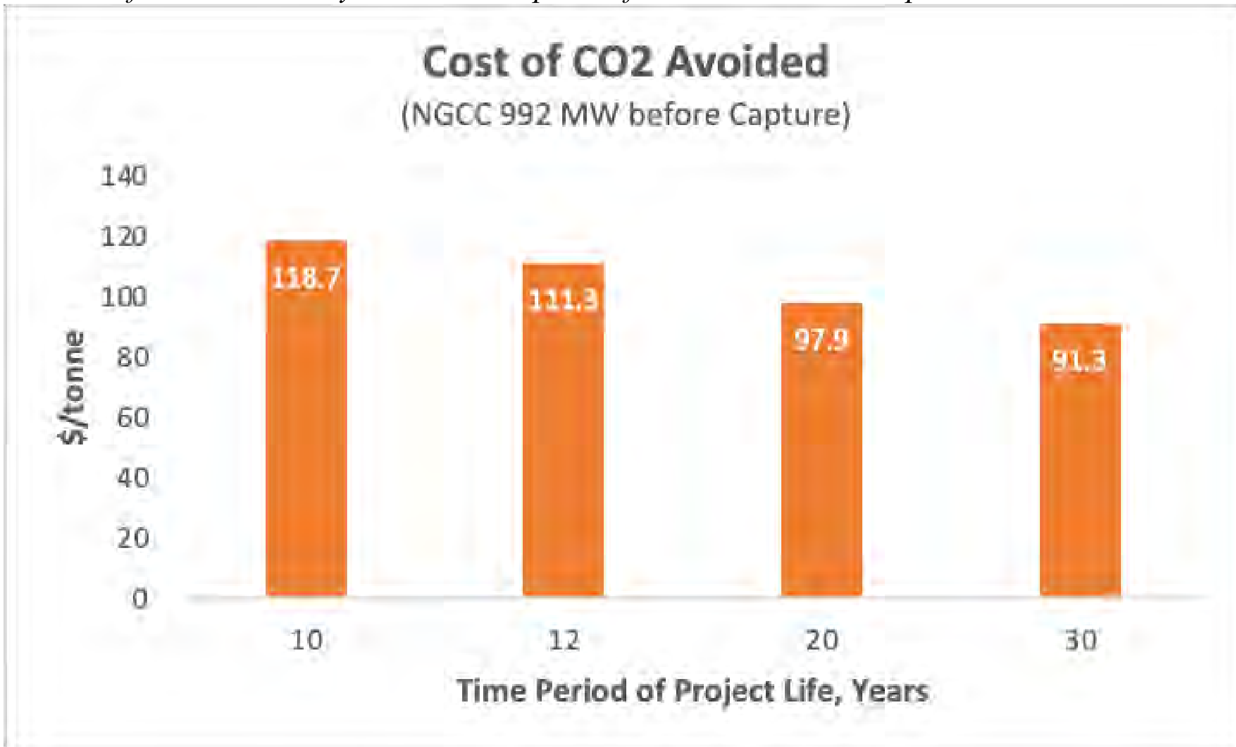
550 *Id.*

551 Costs prepared using NETL NGCC CO_2 Capture Retrofit Database, *supra* note 543, modified to include capital recovery factor based on 12-year period.

Figure 19. Cost of CO2 avoided by amortization period for CCS at an NGCC plant



C. Costs for Gas-Fired Power Plants According to Capacity Factor and Plant Size

EPA reports the following costs for new natural gas plants with CCS:[552]

Table 8. Cost of CCS for New Combustion Turbines

	NETL F-Class, No CCS	NETL F-Class, 90% CCS	NETL H-Class, No CCS	NETL H-Class, 90% CCS	EPA Estimated 90% CCS
Total As Spent Capital ($/kW)	1,040	2,239	1,060	2,115	
Total As Spent Capital of CCS ($/kW)		949		823	1,440
Base Load Rating (MMBtu/h)	4,623	4,623	6,147	6,147	2,000
Net Power Output (MW)	727	645	992	883	279
Derate from CCS (%)		11%		11%	11%
Gross Efficiency (%)	54.6%	51.1%	56.1%	52.5%	51.1%
Net Efficiency (%)	53.6%	47.6%	55.1%	49.0%	47.6%
Increase in Heat Rate from CCS (%)		13%		12%	13%
Design Capture Rate (tonne/h)		255		299	97
Fixed Costs ($/MWh)	3.6	7.4	3.5	6.8	
Increase in Fixed Costs from CCS ($/MWh)		2.3		2.1	5.0
Variable Costs ($/MWh)	1.7	4.0	1.7	3.8	
Increase in Variable Costs from CCS ($/MWh)		2.3		2.1	2.3
LCOE ($/MWh)	49	57	49	52	
Abatement Costs ($/MWh)		6.4		3.5	16
Abatement Costs ($/ton)		19		11	41

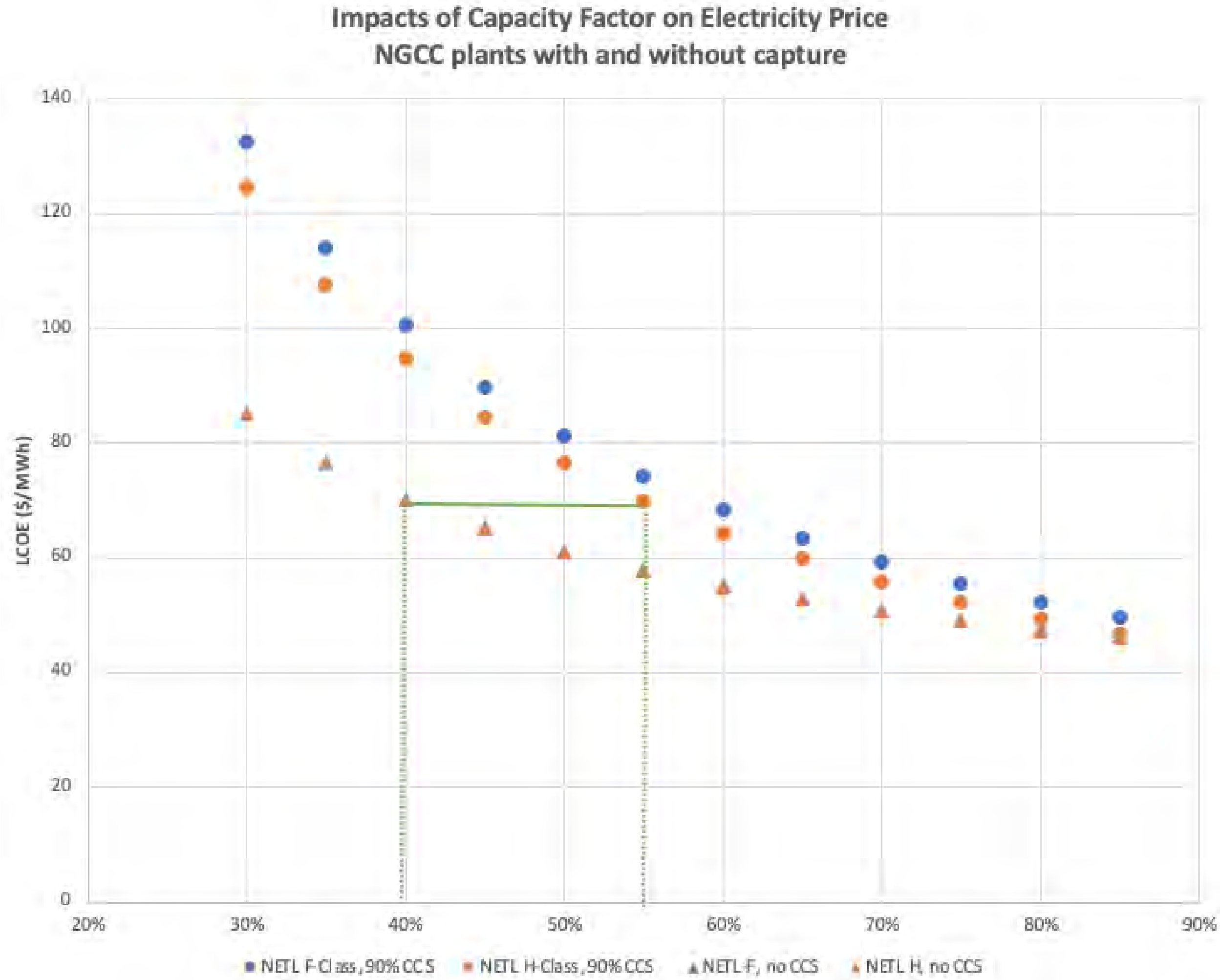
* Assumptions: 12-year amortization, 7 percent interest rate, $3.69/MMBtu natural gas, $85/tonne tax credit, 75 percent capacity factor, and $10/tonne TS&M costs
* Capital and fixed costs on a pre-derate basis

These costs assume a 75 percent capacity factor and account for receiving the $85/ton tax credit. The new uncontrolled F-Class plant shown in the table is 727 MW. If the same plant is built at the outset with 90 percent CCS, the maximum plant output drops to 640 MW. The new uncontrolled H Class NGCC is 992 MW, and building the plant with 90 percent CCS drops the plant output to 883 MW. The larger H-Class plant is more efficient, and this contributes to lower CCS costs.

The plant configurations shown in the table can be adjusted to explore the cost impacts of changing capacity factors. If the capacity factor decreases, the costs of CCS as measured on an LCOE basis increase. If the capacity factor increases, the LCOE falls. The figure below shows the impact of changing the capacity factor for the F-Class and H-Class plants with 90 percent capture and without CCS.[553] Note that the costs of the uncontrolled plants are so similar that they overlap such that only the F-Class data is visible.

[552] EPA, *Technical Support Document: GHG Mitigation Measures for Combustion Turbines*, Docket ID No. EPA-HQ-OAR-2023-0072-0057, at 11, fig.7 (2023) [hereinafter *GHG Mitigation Measures for Combustion Turbines TSD*], https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0057.
[553] Costs developed using EPA spreadsheet, Docket ID EPA-HQ-OAR-2023-0072-0057, Attachment 1 (CCS Costing for combustion turbines), with the following assumptions: CRF 12 years, natural gas price $3.69/MMBTU, $85/ton 45Q credit, 7 percent interest rate, CO_2 T&S 10$/ton.

Figure 20. Impacts of capacity factor on LCOE for NGCC plants with and without CCS



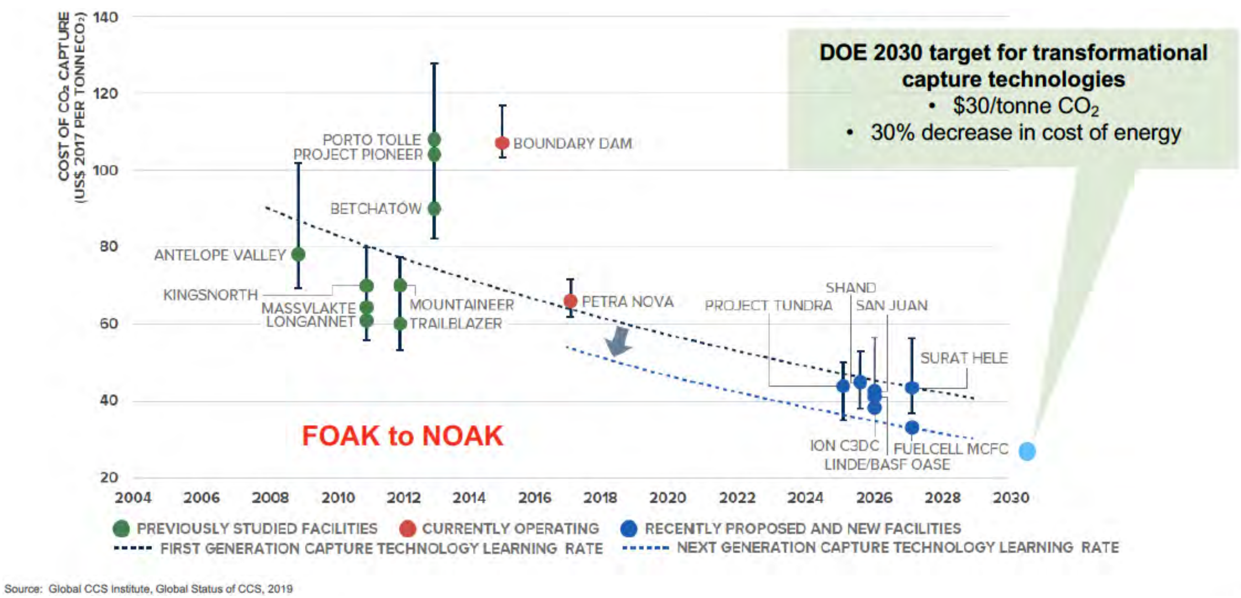
As described in Sec. VI.A.6, Commentors urge EPA to apply the CCS-based standard to new NGCC plants that operate at 40 percent capacity factor or greater. The green lines show that at 40 percent capacity factor, a new uncontrolled NGCC plant has an LCOE of around $70/MWh. An equivalent LCOE for an NGCC with CCS would need to run at 55 percent capacity factor. Plants that add CCS in presence of 45Q can expect the capacity factor to increase compared to an uncontrolled plant. That is because 45Q effectively offsets some variable costs, enabling the CCS equipped plant to advance in the dispatch order. A 2019 Southern Company paper on the impacts of 45Q notes that the tax credit can act as a "bounty" that lowers variable costs and ultimately moves CCS ahead in the dispatch order.[554] In the stylized illustrative example cited in the article, the old $50/ton 45Q tax credit value moved the NGCC plant with CCS from 2 MM MWh/yr of generation to 3 MM MWh/yr. Commenters' IPM Modeling of the proposed rule confirms this effect. In 2035, the models shows a fleet-wide average capacity factor of 44 percent, while plants equipped with CCS operate at 85 percent capacity factor.

[554] Esposito et al., *supra* note 288.

D. Anticipated Cost Declines

EPA's cost analysis is conservative as it is based on current carbon capture vendor estimates and current transportation and storage costs. The Clean Air Act, however, is forward looking and CCS-based standards will not be applicable for coal-fired EGUs until 2030 and gas-fired EGUs until 2035. Significant cost declines are expected in that timeframe making EPA's cost estimates particularly conservative. The figure below shows the significant cost declines expected by 2030.

Figure 21. Expected cost declines for CCS[555]



E. It Is Appropriate to Consider 45Q

EPA appropriately deducts the value of the 45Q credits that eligible regulated sources would almost certainly claim when evaluating the cost of its proposed rules for fossil-fuel-fired power plants. The House and Senate committees in 1970 required EPA to consider achievability and economic feasibility of the standards from the perspective of the regulated industry, which would be improved by tax credits to aid in compliance.[556] Similarly, the D.C. Circuit has suggested that EPA's consideration of costs is properly limited to the regulated industry itself, and potentially its suppliers and customers.[557] Those costs would not include the kinds of transfers of value from the Treasury to power companies and their customers that occur through the awarding of tax credits. Thus, EPA acts consistently with congressional intent in the Clean Air Act and judicial

[555] Global CCS Institute, *Global Status of CCS* (2019) https://www.globalccsinstitute.com/resources/publications-reports-research/global-status-of-ccs-report-2019/.
[556] H.R. Rep. No. 91-1146, at 35 (1970); *see also id.* at 10 (discussion of this provision using nearly identical terms); S. Rep. No. 91-1196, at 91 (1970).
[557] *See, e.g.*, *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975); *Sierra Club v. Costle*, 657 F.2d 298, 330-31 (D.C. Cir. 1981).

precedent in deducting the value of the 45Q credits (and other tax incentives) to determine regulatory costs.

V. Co-Benefits

Many flue gas impurities—including particulates, sulfur dioxide,[558] sulfites,[559] and nitrogen oxides[560]—can degrade amine solvents. That fact means that installation of upstream controls for these pollutants—particularly the sulfur compounds and acid gasses—is considered to be a necessary precondition for the efficient operation of the carbon capture equipment. This presents opportunities for combined reductions in both carbon dioxide and local air pollutants, where additional controls upstream of the capture equipment improve both emissions of local air pollutants and the efficiency of operation of the capture equipment.[561] The operation of the carbon dioxide capture system itself can also directly reduce emissions of some pollutants. In particular, amines react with NO_2, which accounts for around 40 percent of the NOx found in NGCC exhaust, but only 5 to 10 percent of the NOx in coal power plant flue gas. Power plants are unlikely to require additional NOx controls in order to retrofit CO_2 capture, but in some cases such controls may be added in order to minimize the formation of certain degradation products, such as nitrosamines.

Pilot and demonstration-scale applications of amine-based capture systems on coal power have in nearly all cases included an additional 'SO_2 polishing' step which removes remaining SO_2 and SO3 from the flue gas, even where it has already been treated with conventional flue gas desulfurization (FGD). Researchers indicate that SO_2 concentrations need to be below 10 ppmv for economic post-combustion capture using amines and even lower levels for some other technologies like membranes.[562] This polishing step is often carried out in the direct contact cooler (in which water is introduced to the hot flue gas for cooling), through addition of alkali species (NaOH, Na_2CO_3) to the cooling water. If not removed, SO_2 will react with amines to form heat stable salts, which can alternatively be eliminated in the solvent reclaimer.[563] In both cases, SO_2 pollution in the flue gas will be reduced.

NO_2 can react with secondary amines to form nitrosamines, a regulated carcinogenic species whose formation and potential release has been shown to be controllable through mechanisms

[558] Shan Zhou, Shujuan Wang, Chenchen Sun, Changhe Chen, *SO_2 effect on degradation of MEA and some other amines*, 37 Energy Procedia 896 (2013), https://www.sciencedirect.com/science/article/pii/S187661021300194X.
[559] Takashi Kamijo et al., *SO3 Impact on Amine Emission and Emission Reduction Technology*, 37 Energy Procedia 1793 (2013), https://www.sciencedirect.com/science/article/pii/S1876610213002993 (flue gas SO3 results in additional amine emissions).
[560] Berit Fostås et al., *Effects of NOx in the flue gas degradation of MEA*, 4 Energy Procedia 1566 (2011), https://www.sciencedirect.com/science/article/pii/S1876610211002232.
[561] *See* Great Plains Institute, *Carbon Capture Co-benefits* (Aug. 2023) [Attachment 6].
[562] *See, e.g.*, Kevin Smith, William Booth, & Stephane Crevecoeur, Carmeuse Lime & Stone, *Evaluation of Wet FGD Technologies to Meet Requirements for Post CO_2 Removal of Flue Gas Streams* (2008), https://www.mass.gov/doc/appendix-d25-exhibit-4-to-comments-from-scclf/download (EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium, Paper #49); Purswani & Shawhan, *supra* note 382.
[563] Gibbins & Lucquiaud, *supra* note 444.

such as use of water washes.[564] Primary amines react with NO_2 to form unstable compounds that degrade into various species of less concern that can be removed in solvent reclaiming. For this reason, capture systems including secondary amines—particularly when applied to NGCC—may have an incentive to further reduce NO_x entering the capture system, in addition to any existing upstream NO_x controls. This could be done, for example, by adding sulfites or thiosulfates to the direct contact cooler.

Coal power plants produce particulates (fly ash) which are removed with particulate control devices such as baghouses and electrostatic precipitators. Where present, further removal of particulates is achieved by wet flue gas desulfurization. Solvent-based CO_2 capture technologies require very low concentrations of particulates entering the system, as they can cause unwanted fouling of process components such as heat exchangers; this was encountered during the early operation of Boundary Dam 3, where upstream controls were electrostatic precipitators that allowed some finer fly ash to pass through.[565] As a result, water sprays were later added to prevent particulates from entering the CO_2 capture system—also preventing them from reaching the air, as they had been previously. Most amine-based CO_2 capture processes also include a direct contact cooler, which also acts as an important trap for particulates in plants without wet desulfurization.[566]

A. Co-benefits Calculations using EASIUR

A recent Resources for the Future working paper evaluated several coal plant FEED studies and determined that SO_2 pollution levels were expected to be reduced 99 percent.[567] Using this 99 percent SO_2 reduction, we estimate installing CCS on the fleet of 133 existing coal power plants over 300 MW capacity would cut 250,000 tons of SO_2 pollution each year. This includes reductions from plants with existing desulfurization units installed that are now operating under 99 percent capture efficiency as indicated by the EIA 860 report and is based on 2021 annual emissions as reported in eGRID.

Using a reduced form, spatially explicit tool based on a chemical transport model for calculating marginal social costs from health impacts and premature mortality from point source emissions called EASIUR, these co-pollutant reductions result in 4.33 billion dollars per year in avoided social costs.[568] This equates to 500 lives saved per year from SO_2 reductions alone.

VI. Water Consumption

Some carbon capture configurations can increase water consumption, primarily because of the cooling water required to cool down the CO_2-containing gasses before they are treated, as well as cooling other parts of the process. The amount of water consumed depends significantly on the type of cooling used by the plant and the CO_2 capture technology used, and does not necessarily

[564] Nathan A. Fine & Gary T. Rochelle, *Absorption of nitrogen oxides in aquerous amines*, Energy Procedia, Vol. 63 (2014), https://www.sciencedirect.com/science/article/pii/S1876610214019092; Fostås et al., *supra* note 560; H. Kolderup et al., SINTEF Report A18095 on Emission Reducing Technologies (Feb. 14, 2011), https://gassnova.no/app/uploads/sites/6/2019/10/emissionredtechnologies_sintef.pdf
[565] *Wood Report*, *supra* note 418.
[566] Gibbins & Lucquiaud, *supra* note 444.
[567] Purswani & Shawhan, *supra* note 382.
[568] Assuming a value of statistical life (VSL) of $8.7M in 2015$ per the BenMAP manual.

increase relative to an unabated plant. The impact of carbon capture on water consumption depends on the type of cooling selected by the developer. There are three options for cooling coal and natural gas-fired power plants:[569]

> 1. Dry cooling (also called air cooling): Dry cooling systems reject heat in the plant's hot water directly to the atmosphere using air-cooled condensers (ACCs). These systems do not consume cooling water.
>
> 2. Wet cooling: A wet cooling tower cools hot water and recirculates it to a condenser. Cooling towers can be natural-draft or mechanical-draft. Water consumption can be highest if using an amine-based CO_2 capture system and closed-loop wet cooling, potentially representing a 20 to 30 percent increase for a coal power plant.[570]
>
> 3. Hybrid cooling: Hybrid cooling combines both the wet and dry cooling approaches. Generally, the plant uses dry cooling during cooler weather and wet cooling during hot periods when dry cooling systems are less effective.

These three cooling options were detailed in a carbon capture context by the first proposed new coal plant with 90 percent capture to receive an air permit – Tenaska's 600 MW-n Trailblazer plant, which was to be located in Sweetwater, Texas.[571] The Trailblazer plant location had easy access to EOR fields and rail access for sub-bituminous low-rank coal but the site was water constrained. As part of the development process, the Global CCS Institute funded Tenaska to prepare a report that documented their cooling technology options and selection for the project.[572] Tenaska examined three options: wet cooling, hybrid cooling and dry cooling. For each configuration, they examined water consumption when the capture unit was turned on (capturing 90.5 percent of the plant's CO_2) and when the capture unit was off (no capture). The figure below summarizes in millions of gallons per day of water the average water consumption findings from the report:

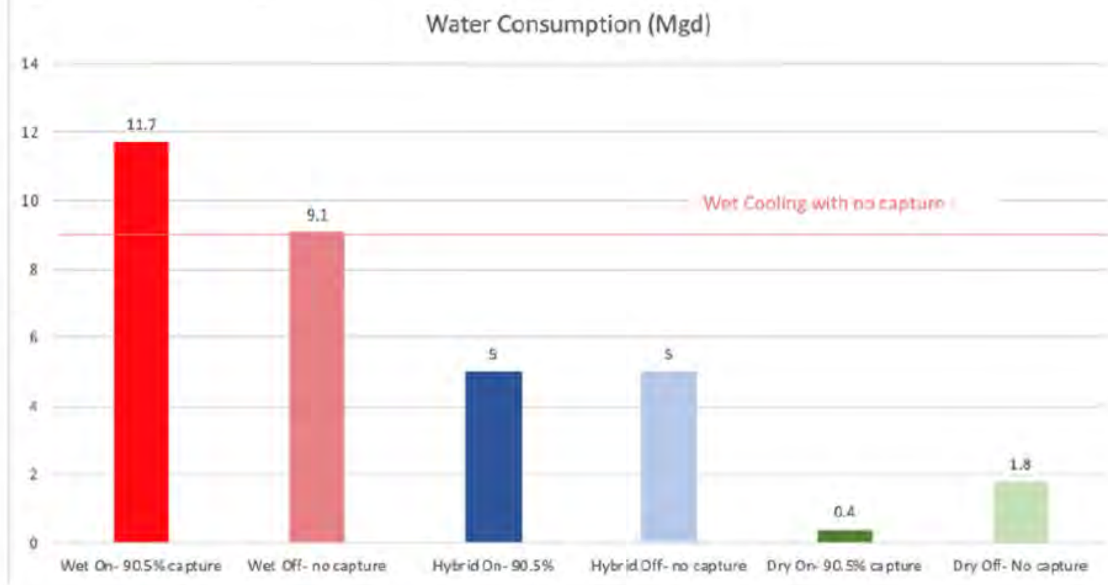
[569] Kevin Clark, *Evaluating the Economics of Alternative Cooling Technologies*, Power Engineering (Nov. 1, 2012), https://www.power-eng.com/coal/evaluat-economics-alternative-cool-technologies/.

[570] GCCSI, *Water use in thermal power plants equipped with CO_2 capture systems* at 44-45 (Sept. 2016), https://www.globalccsinstitute.com/archive/hub/publications/200603/Water%20use%20in%20thermal%20power%20plants%20equipped%20with%20CO2%20capture%20systems.pdf.

[571] The plant was issued an air permit by the Texas Commission on Environmental Quality on December 30, 2010. EPA, *TX-0585*, RACT/BACT/LAER Clearinghouse (last updated: Feb. 3, 2020), https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.FacilityInfo&facility_id=27221.

[572] Tenaska Trailblazer Partners, LLC, *Cooling Alternatives Evaluation for a New Pulverized Coal Power Plant with Carbon Capture* (Aug. 2011), https://www.globalccsinstitute.com/archive/hub/publications/24367/cooling-study-report-2011-09-06-final-w-attachments.pdf.

Figure 22. Water consumption for 90 percent capture; Tenaska Trailblazer coal plant[573]



As the figure shows, wet cooling requires the most water consumption. Using carbon capture increases the water consumption requirements by 29 percent on an average basis, although the range for this plant varied from 25–40 percent depending on ambient temperature conditions.[574] Dry cooling requires the least amount of water. Compared to wet cooling, dry cooling reduces water consumption by over 96 percent. Tenaska's report noted an important fact about carbon capture when using dry cooling, "the [Carbon Capture (CC)] Plant *decreases* water consumption by 40 – 80 percent which equals 0.8 to 1.4 mgd (3,028 – 5,300 m3/d) depending on the ambient condition. This is because the CC Plant includes an upfront cooling step that condenses combustion water vapor which is re-used in the PC Plant."[575] The hybrid case, which combines dry and wet cooling, reduced water consumption by more than half compared to the wet-cooled carbon capture case. Significantly, regardless of whether carbon capture was turned on or off, hybrid cooling consumed the same amount of water. Again, the condensed water from the carbon capture plant was sufficient to offset cooling requirements of carbon capture because the hybrid approach includes some dry cooling.

Tenaska found that both hybrid and dry cooling technology were available for their project, for which Fluor carried out the project design and costing. As Tenaska notes, "Fluor has determined that it is feasible to air cool the CC Plant Econamine FG+ technology and achieve the desired

[573] *Id*. at 21.
[574] *Id*.
[575] *Id*. at 22.

CO_2 capture rate at the Trailblazer site ambient conditions."[576] Dry cooling was also economic. Tenaska concluded that dry cooling was the lowest cost option for the Trailblazer plant.[577]

This finding that hybrid cooling does not lead to increased water consumption was affirmed by a recent feasibility study on SaskPower's Shand Plant.[578] The 305 MW Shand Plant burns low-rank lignite and is located in a water-constrained area. Using hybrid cooling, the feasibility found, "The only new water used in the system is the water that is condensed out of the unit's flue gas. The use of a hybrid cooling system with dry coolers and wet surface air coolers … has the potential to be a reasonable first approach to cooling at any coal-fired power plant and is especially effective with high moisture low-rank coals."[579]

VII. Space Constraints

CATF conducted a systematic assessment of land availability surrounding the existing US fleet of coal and natural gas plants to determine the physical feasibility of retrofitting them with post-combustion carbon capture technology. While many plants likely have space within the existing plant boundary, this study focuses on adjacent land as a conservative way to assess the limitation. In some cases, it may be more cost effective to purchase more land rather than engineer around a crowded plant site, or a site may simply be too crowded such that additional land may be required to accommodate the retrofit facilities.[580] If a plant has the required area of land adjacent to its boundary, then regardless of whether or not it has land available within its boundary, we can consider a carbon capture retrofit as being spatially feasible.

Using an assumed footprint for carbon capture infrastructure based on demonstration sites, scaled accordingly to meet installed capacities and a maximum allowable distance of one mile from the plant boundary, CATF found that the vast majority of coal and NGCC plants in the US have land available in the immediate vicinity upon which capture infrastructure could be constructed. Across the entire U.S. fleet of coal and natural gas power plants greater than 300 MW, 133 coal plants and 140 NGCC plants (i.e. all but 2 and 3 plants, respectively) were found to have sufficient land availability for carbon capture retrofits (Table 9). Importantly, this is an underestimate of the number of candidate fossil fuel plants because it does not account for the likely case that land is available within the existing plant boundary. It is also likely a

[576] *Id.*

[577] *Id*. at 6. After the initial design work was completed, Tenaska received bids for the dry cooling option. These bids were higher than expected: "The result of the competitive bidding process for the air coolers was higher costs than were previously estimated. In addition, the final design included raising the height of the air coolers and including a lower design air velocity with an increased fin spacing. A 20 percent spare heat transfer surface area was included in the design basis, but variable frequency drives or two-speed fans were not considered. Had these impacts been known at the point in time when the cooling study was completed, the hybrid cooling option may have provided the lower evaluated cost (although its cost may have been affected somewhat similarly). Even so, with the lack of water available for the Project in semi-arid West Texas, there is a high probability that dry cooling still would be a necessity." *Id*. at 25.

[578] Int'l CCS Knowledge Ctr., *The Shand Feasibility Study* (Nov. 2018); https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.

[579] *Id*. at 12.

[580] Christopher Nichols, *Coal-Fired Power Plants In The United States- Examination Of The Costs Of Retrofitting With CO_2 Capture Technology* (2019), https://www.globalccsinstitute.com/archive/hub/publications/119731/coal-fired-power-plants-us-examination-costs-retrofitting-co2-capture-technology.pdf.

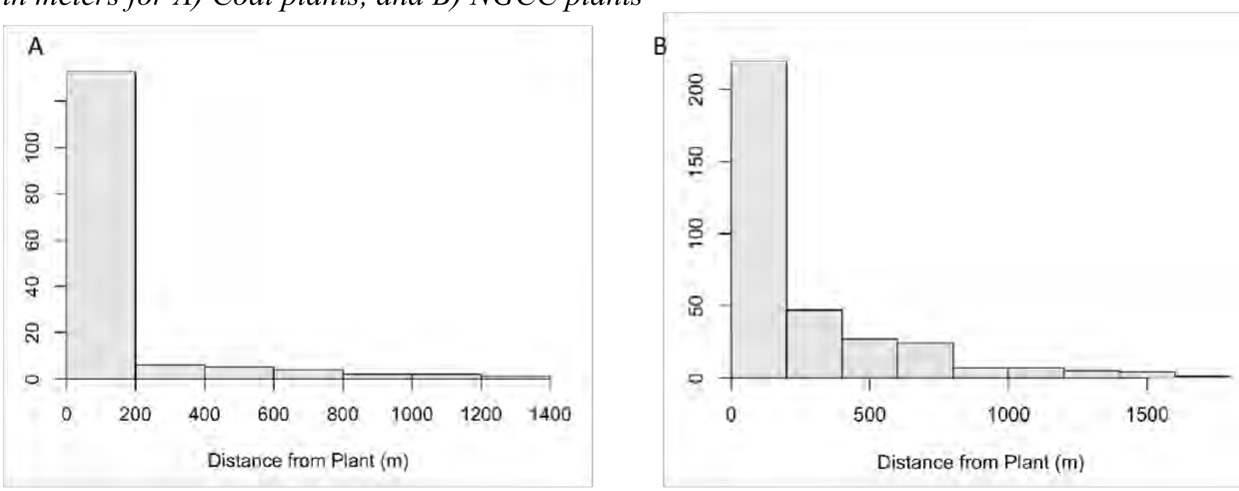
conservative estimate because the footprint of carbon capture facilities will decrease over time as we progress from demonstration sites to full scale installations.

Table 9. Results of the analysis showing the number of plants and associated percentage of total installed capacity that could feasibly be retrofitted with carbon capture from a land availability perspective

	Available Land (# plants)	No land for CC retrofit (# plants)	Total retrofittable capacity (GW)	Total Installed Capacity (GW)	Percentage MW Capturable (%)
Coal	133	2	154	157	**98.2**
NGCC	140	3	124	126	**98.4**

Although one mile (about 1610 meters) was used as the maximum distance, it is important to note that the vast majority of plants (83 percent and 72 percent for coal and NGCC, respectively) have the nearest available plot of land within 100 meters of the plant boundary (Figure 23). This is significant because the shorter distance the flue gas must be transported, the more cost-efficient the process becomes.

Figure 23. Histograms showing the distance between the nearest patch and the plant boundary in meters for A) Coal plants, and B) NGCC plants



VIII. Operational Flexibility

As the proportion of variable renewable energy (wind and solar) on the grid grows, dispatchable power plants will increasingly be expected to provide more flexible generation, with more frequent ramping, and more start-up and shut-down cycles. Consequently, there is also a growing body of research on the flexible operation of coal and gas power plants equipped with carbon capture. This research has included both modeling and large-scale pilot tests (for example, at Technology Centre Mongstad, CSIRO, PACT, and the University of Texas).[581]

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[581] Bui et al., *Demonstrating flexible operation of the Technology Centre Mongstad (TCM) CO_2 capture plant*, 93 Int'l J. Greenhouse Gas Control 102879 (2020), https://www.sciencedirect.com/science/article/abs/pii/S1750583615301687; Bui et al., *Evaluating Performance*

As a result of this growing understanding of capture plant flexibility, developers of the planned NGCC with CCS in the UK are confident that the facilities will be able to operate in the UK grid while maintaining average capture rates at levels commensurate with proposed UK funding requirements. These support contracts require that capture rates of no less than 10 percentage points below their target capture rate (typically 95 percent) are maintained during start up; as a consequence proposed projects have tested their designs against flexible operating regimes, including 200 start-up shut-down events of various types (cold, warm, hot).[582] Given that the capacity factors of combined cycle plants in the UK have declined to an average of 35 percent in 2020, CCS-equipped NGCC can be expected to operate in a highly flexible manner (although will be dispatched ahead of unabated plants).

The level of dynamic integration of power generation and CO_2 capture will differ according to whether the capture process is separately powered or uses steam extracted from the power plant's steam cycle. A recent study reviewed prior work in this field and conducted dynamic modeling of an integrated (615 MW) NGCC and CCS system.[583] In relation to load cycling operation, it concludes that "the decarbonization of an NGCC via post-combustion CO_2 capture does not appear to impose any limitation on the flexibility or operability of the underlying power plant in terms of power generation."[584] Flexibility of the integrated plants can benefit from buffering provided by large liquid hold-ups (e.g., through larger solvent vessels), as well as advanced system controls such as model predictive control (which are now standard for power plants but require optimization for CCS-integrated systems).

Rapid start-up of the power plant may be hindered by the slower start-up times of the capture plant (particularly for cold start-ups).There are several commonly proposed approaches to mitigating this effect. These include the use of dedicated solvent storage, which allows CO_2 to be captured before the solvent regenerator reaches operating temperatures (solvent storage can also be used to optimize power plant operation according to varying electricity demand and price).[585] Alternatively, a small heater or auxiliary boiler (potentially electrically powered) can be used to provide preheating or additional steam for solvent regeneration. A detailed modeling study for the UK government in 2020 examined means of accelerating start-up and shut-down times of a

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During Start-Up and Shut Down of the Tcm CO_2 Capture Facility (Nov. 23, 2022), Proceedings of the 16th Greenhouse Gas Control Technologies Conference (GHGT-16) 23-24 Oct 2022, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4284866; Bui et al., *Flexible operation of CSIRO's post-combustion CO_2 capture pilot plant at the AGL Loy Yang power station*, 48 Int'l J. GHG Control 188-203 (2016), https://www.sciencedirect.com/science/article/pii/S1750583615301687; Bui et al, *Dynamic operation and modelling of amine-based CO_2 capture at pilot scale*, 79 Int'l J. GHG Control 134-153 (2018), https://www.sciencedirect.com/science/article/pii/S1750583618304250.

582 UK Department for Business, Energy and Industrial Strategy, *An update on the dispatchable power agreement* (May 2021), https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/984402/dpa-update-may-2021.pdf; Aker Carbon Capture (2023) (market discussion with CATF staff).

583 Rua et al., *Does CCS reduce power generation flexibility? A dynamic study of combined cycles with post-combustion CO_2 capture*, 95 Int'l J. GHG Control 102984 (2020), https://www.sciencedirect.com/science/article/pii/S1750583619306747.

584 *Id.*

585 Niall Mac Dowell & Neelkumar Shah, *Optimisation of Post-combustion CO_2 Capture for Flexible Operation*, 63 Energy Procedia 1525 (2014), https://www.sciencedirect.com/science/article/pii/S1876610214019778.

state-of-the-art gas-fired power plant with CCS (steam extraction for solvent regeneration).[586] Four modified plant configurations were proposed to enhance capture rates during start-ups, including segregating solvent inventory between the regenerator and absorber loops during start-up; additional solvent buffer storage; dedicated heat storage for regenerator preheating; and fast-starting steam cycle technologies or high-pressure bypass extraction. Each of these approaches was determined to be suitable for maintaining capture rates above 95 percent throughout start-up, except for segregated solvent inventory (87 percent); this option could, however, be used in combination with other methods to reduce costs. The UK government has also funded the FOCUSS project, led by SSE Thermal and involving the U.S. National Carbon Capture Center, which aims to reduce the cost of achieving very high capture rates (up to 99 percent) during flexible operation.[587]

IX. Parasitic Load

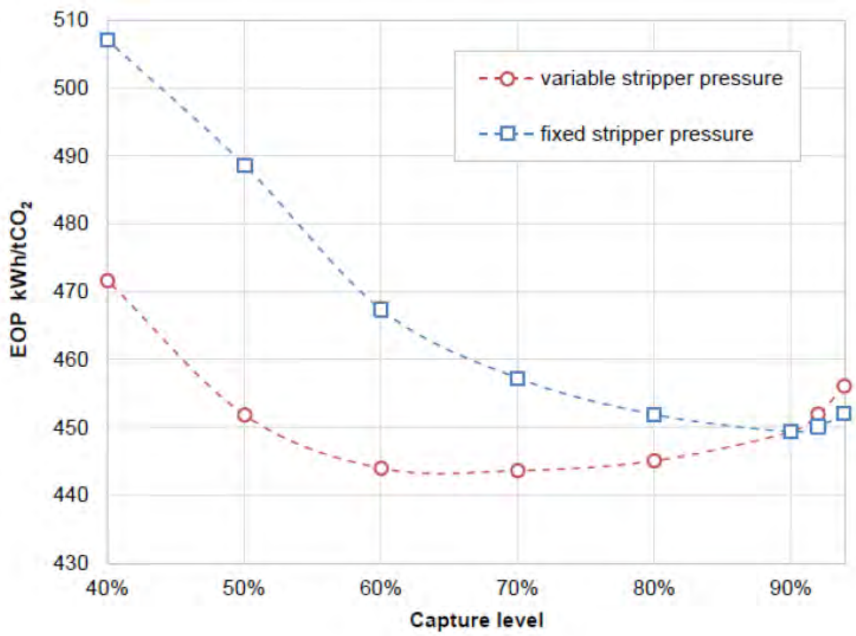
Like most pollutant control technologies, CO_2 capture incurs an energy penalty and will reduce the net power output of the plant. For the solvent-based capture processes mostly considered for power plants today, this penalty is largely associated with the heat energy needed to separate CO_2 from the solvent in the desorber/stripper. This heat is usually supplied by steam which can either be extracted from the power plant's own steam cycle (prior to the low-pressure turbine) or generated by a separate unit. Additional electrical energy is also required to compress CO_2 and run various fans and pumps needed to drive the capture process.

A detailed techno-economic analysis carried out by Wood Group for the IEA Greenhouse Gas R&D Programme determined some benchmark energy penalties for new coal-fired power plants (1000 MW) and NGCC plants (1500 MW) equipped with CCS. This study found the coal plant would incur a 20 percent reduction in net efficiency at 90 percent capture rate, and a 24 percent reduction for 99 percent capture. The NGCC plant suffers only a 10 percent loss of net output at 90 percent capture, and a 12.6 percent penalty at 99 percent capture. NETL benchmark retrofit cases indicate energy penalties of between 11 percent and 12.5 percent for various NGCC cases with 90 and 95 percent capture. The UK's BAT review for post-combustion capture also states the energy penalty "will correspond to between approximately an eighth (for gas) and a quarter (for biomass) of the power plant's electricity output without CO_2 capture" (bearing in mind biomass power plants are roughly equivalent to coal in this context). Figure 24 indicates how the energy output penalty (EOP) can vary with capture rate.

[586] U.K. Dep't for Bus., Energy & Indus. Strategy, *Start-up and shut-down of power carbon capture, usage and storage (CCUS) facilities*, BEIS No. 2020/031 (Aug. 17, 2020), https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/929284/AECOM_report_final_version_clean_inc_appendices.pdf.

[587] University of Sheffield's Translational Energy Research Centre (TERC), *Carbon capture rates in FOCUSS as SSE Thermal secures grant from BEIS* (May 31, 2022), https://terc.ac.uk/news-events/carbon-capture-rates-in-focuss-sse-grant-beis/.

Figure 24. Total electricity output penalty of CO_2 capture and compression at different capture levels under variable and fixed stripper pressure operation[588]



The FEED studies detailed in Tables 2 and 3 can provide an indication of typical energy penalties for retrofit cases on coal and gas plants. Plant Daniel NGCC has a total net output of 525 MW without CCS, which is calculated to be reduced by 79 MW (15 percent) when 90 percent capture is applied. Panda Sherman NGCC (total net output 719 MW) incurs a penalty of 67.3 MW (16 percent) capturing 85 percent of a flue gas slipstream equivalent to 420 MW. Mustang NGCC uses additional boilers (rather than steam extraction from the power plant) to drive the CO_2 capture process, but the equivalent energy penalty can be calculated as 106 MW over 480 MW gross output (22 percent).

For coal plants, the repowered Boundary Dam Unit 3 generates around 150 MW net output without CCS, and 115 MW with CCS (a 24 percent energy penalty); however, this penalty also includes the operation of the desulfurization unit.

It is worth noting that the 2021 average capacity factor for coal-fired EGUs is 48 percent and for NGCC it is 57 percent, so there is clearly adequate surplus capacity to dedicate to the operation of post-combustion capture.

X. Construction Timeline

Evidence from operational, under construction, and planned large-scale CO_2 capture plants indicates that they typically take around two to three years to complete construction (Table 10). These construction times may be expected to accelerate as experience grows and equipment

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588 Olivia Errey, *Variable capture levels of carbon dioxide from natural gas combined cycle power plant with integrated post-combustion capture in low carbon electricity markets* (2018), https://era.ed.ac.uk/bitstream/handle/1842/33240/Errey2018.pdf?sequence=1&isAllowed=y.

becomes more standardized. However, supply chains for key components may also require scaling up to prevent bottlenecks.

Table 10. Construction timelines of some large-scale CO_2 capture plants using amine solvent technology

Project	Capacity (Mt/year)	FID	Construction start	Expected or actual completion
Boundary Dam[589]	1	2010	Early 2011	Dec 2013
Petra Nova[590]	1.4	Early 2014	Sep 2014	Jan 2017
Quest (hydrogen)[591]	1.2	2012	Sep 2012	Aug 2015
Brevik (cement)[592]	0.4	2021	Jan 2021	Early 2024
Heidelberg Materials Edmonton (cement)[593]	0.6	Expected 2023	Not started	Late 2026
Net Zero Teesside Power (NGCC)[594]	2	Expected Q1 2024	Not started	2027
Genesee CCS project (NGCC)[595]	~3	Expected 2023	Not started	2027
Orsted Asnaes and Avedore (two biomass CHP)[596]	0.15 and 0.28	May 2023	Not started	Early 2026

[589] IEAGHG, *Integrated carbon capture and storage project at Saskpower's Boundary Dam power station* (2015), https://ieaghg.org/docs/General_Docs/Reports/2015-06.pdf.
[590] Petra Nova, *supra* note 413.
[591] IEAGHG, *The Shell Quest Carbon Capture and Storage Project* (2019), https://documents.ieaghg.org/index.php/s/5LUE9dQjnqPIKCr.
[592] Heidelberg Materials, *Project status Brevik CCS*, Brevik CCS (2023), https://www.brevikccs.com/en/status.
[593] *First global net zero carbon capture and storage facility in the cement industry: Heidelberg Materials partners with the Government of Canada*, Heidelberg Materials (Apr. 6, 2023), https://www.heidelbergmaterials.com/en/pr-2023-04-06.
[594] *Net Zero Teesside (NZT) Power named on DESNZ's Track 1 Negotiations Project List*, Net Zero Teesside (Mar. 30, 2023), https://www.netzeroteesside.co.uk/news/net-zero-teesside-nzt-power-named-on-desnzs-track-1-project-negotiation-list/.
[595] *Capital Power advances plans for Genesee CCS Project*, Capital Power (Dec. 1, 2022), https://www.capitalpower.com/media/media_releases/capital-power-advances-plans-for-genesee-ccs-project/.
[596] *Ørsted awarded contract – will capture and store 430,000 tons of biogenic CO2*, Ørsted (May 15, 2023), https://orsted.com/en/media/newsroom/news/2023/05/20230515676011.

Appendix B - Low-GHG Hydrogen Co-Firing

I. Introduction

Hydrogen is energy intensive to produce, transport, and use, making it prudent to prioritize where it is deployed as a decarbonization solution. While low-GHG hydrogen co-firing is cost reasonable and adequately demonstrated for the relevant portions of the new gas-fired fleet, it may be prudent to prioritize its use in other sectors. Low-GHG hydrogen will likely play a vital role in achieving economy-wide decarbonization through the novel use in harder-to-abate sectors like long-haul trucking, steel production, the direct replacement of existing unabated hydrogen that is used for ammonia production and refining, and the production of fuels vital for low-carbon maritime shipping and aviation. Low carbon electricity is likewise valuable and should be prioritized toward high-value decarbonization efforts, such as displacing existing high-emission generation from the grid.

If deploying hydrogen in the power sector, low-emissions hydrogen should likely be limited to co-firing in low and intermediate load power plants.[597] While co-firing technology is adequately demonstrated, projected low-GHG hydrogen prices make it expensive to implement for all but low and intermediate low power plants. There is a lack of cost effective alternatives for these lower capacity plants given that lower run times makes it more difficult to recover the initial, significant capital costs of solutions like CCS. For base load power plants, CCS is cheaper to implement and should be considered the sole BSER instead.

As EPA provides in the *Hydrogen in Combustion Turbine Electric Generating Units TSD*, and Commenters describe in Sec. VI.B of the Comments, there is considerable industrial experience making and using hydrogen, that is being transferred to the power sector.[598] Some current commercial offerings from the major turbine Original Equipment Manufacturers (OEM) can operate on up to 30 percent–50 percent ratios of hydrogen/natural gas (by volume) using dry low-NOx combustors and even higher using diffusion combustors, with higher ratios available for new larger models. Further, several OEMs have committed to offering 100 percent-hydrogen capable machines by 2030. Indeed, GE already has two turbine models that can operate on 100 percent hydrogen.[599]

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[597] The discussion in this section is mostly limited to hydrogen turbines rather than hydrogen fuel cells given that EPA's proposal is focused on the former.

[598] EPA may also base standards upon "the reasonable extrapolation of a technology's performance in other industries." *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1978) (finding it appropriate, and in line with the purposes of the Clean Air Act, to rely on technology transfer from other industries).

[599] EPA, *Technical Support Document: Hydrogen in Combustion Turbine Electric Generating Units*, Docket ID No. EPA-HQ-OAR-2023-0072-0059, at 7 (2023) [hereinafter *Hydrogen TSD*], https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0059.

Table 11. Hydrogen Capabilities in Certain Models of Combustion Turbines[600]

Manufacturer	Turbine Model/Type	Current Hydrogen Capability[1]	Future Hydrogen Capability[2]
GE Gas Power			
	Aeroderivative	85%	100%
	B/E-Class	100%	
	F-Class	100%	
	HA-Class	50%	100%
Siemens Energy			
	SGT5/6-9000HL	50%	
	SGT5/6-8000H	30%	
	SGT-700	75%	
	SGT-750	40%	
Mitsubishi Heavy Industries			
	M501GAC	30%	100%
	M501JAC	30%	100%
	M701JAC	30%	100%
[1] The actual % by volume hydrogen levels may vary based on combustion turbine model, combustion model, combustion system, and overall fuel consumption. Turbines currently co-firing greater than 30% hydrogen by volume typically utilize wet, low-emission (WLE) or diffusion flame combustors. [2] Manufacturers are developing DLN combustor modifications for several turbine models that will allow for increased hydrogen firing while limiting emissions of NO_X. These include pre-planned small modification or retrofits kits for certain models to increase their levels of hydrogen combustion.			

EPA must utilize its authority under the Clean Air Act to press the state-of-the-art methods of pollution control forward.[601]

In this Appendix, Commenters expand upon issues associated with 1) policy considerations about the best use of low-GHG hydrogen supply; 2) emission reductions associated with co-firing low-GHG hydrogen; 3) effective management of potential NOx emissions; 4) costs of co-firing low-GHG hydrogen; 5) definition and verification of low-GHG hydrogen; 6) severability of the low-GHG requirement; and 7) a recommendation to list and set Section 111 standards and emission guidelines for the hydrogen production source category.

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[600] *Id.*

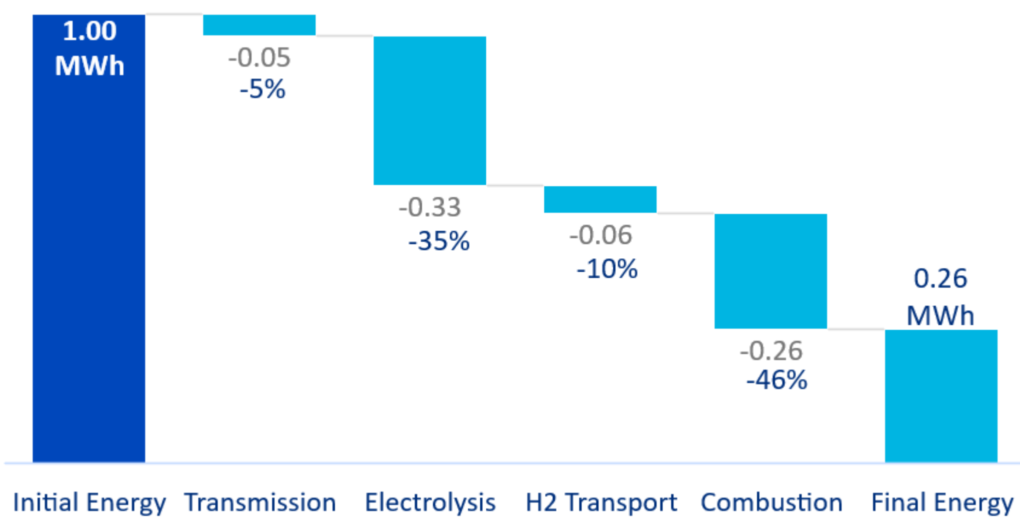
[601] Siemens Gas and Power GmbH & Co., *Hydrogen power with Siemens gas turbines*, fig.3 (Apr. 2020), https://internationalgbc.org/wp-content/uploads/2021/07/0718_hydrogencapabilitesgt-april-2020.pdf; EPRI, *Technology Insights Brief: Hydrogen-Capable Gas Turbines for Deep Decarbonization*, tbl.2 (Nov. 2019), https://www.epri.com/research/products/000000003002017544; EU Turbines, *Commitments*, https://www.euturbines.eu/power-the-eu/gas-turbines-renewable-gas-ready/commitments/#:~:text=At%20the%20beginning%20of%202019,renewable%20and%20low%2Dcarbon%20gases (last visited Jun. 3, 2022).

II. While Low-GHG Hydrogen Co-Firing Is Cost Reasonable and Adequately Demonstrated for the Relevant Portions of the New Gas-Fired Fleet, Hydrogen Supply May Be Best Utilized in Other Sectors

Low-carbon hydrogen is an important pillar to reducing emissions from various heavy industries, but it is far from the "Swiss army knife" of decarbonization. Hydrogen is energy intensive to produce, transport, and use, making it a priority to deploy this molecule where electrification is commercially or technically impossible. Low-carbon electricity is a valuable resource and should thus be prioritized toward high-value decarbonization efforts, such as displacing existing high-emission generation from the grid.

Consider the round-trip efficiency of burning electrolytic hydrogen as an example. Starting with 1 MWh of electricity, the conversion losses of transmitting the electricity, breaking apart water using electrolysis, transporting the hydrogen, and finally combusting it in a combined cycle turbine would result in a loss of 74 percent of the initial energy inputted into the process (only about 0.26 MWh of the initial energy would remain). The calculation shown in the graph below assumes PEM electrolyzers are used for electrolysis, hydrogen transport is done at 80 bar via pipeline, and hydrogen is combusted in a simple cycle turbine with around 53.7 percent efficiency.

Figure 25. Conversion losses when using electrolytic hydrogen for power in a combined cycle turbine[602]



Rather than deploying low-carbon hydrogen in sectors where it is highly inefficient, low-carbon hydrogen should be given priority toward sectors that are difficult or impossible to electrify (commercially or technically)—or "no regret" sectors—first. In the near-term, low-carbon hydrogen should be used to displace existing unabated end uses of hydrogen. Today, hydrogen consumption is around 94 million tons annually (MT/y) and is almost entirely used as a chemical

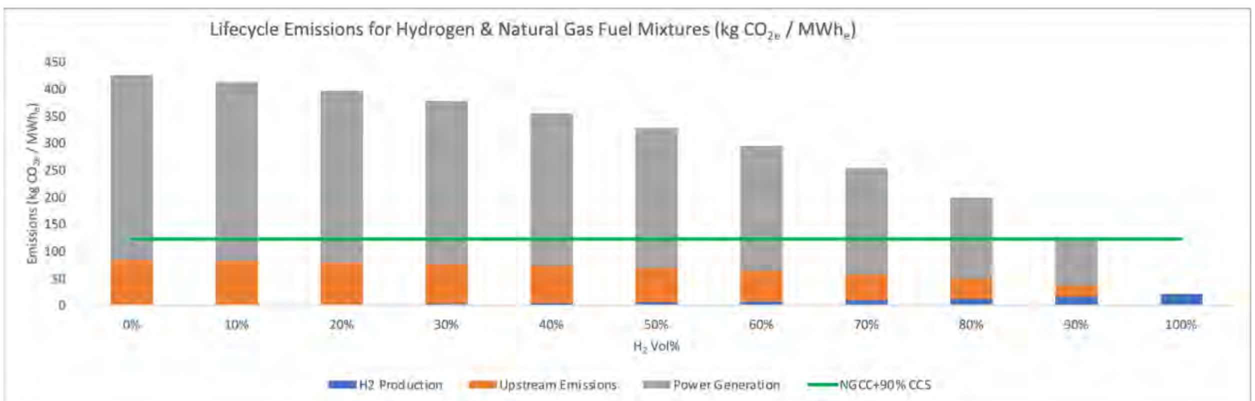
[602] Plant operating data obtained from EIA, *Cost and Performance Characteristics of New Generating Technologies* in *Annual Energy Outlook 2022* (2022), Table 1, https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

feedstock (not as a fuel) in refining (40 MT/y), ammonia production (34 MT/y), methanol (15 MT/y), and steel manufacturing (5 MT/y). Most of the hydrogen used in these applications is generated through unabated, fossil-based methods. Hydrogen should thus be given priority toward sectors that are difficult or impossible to electrify (commercially or technically) or that require hydrogen as a feedstock. These "no-regret" sectors likewise may include newer uses like biofuels processing, sustainable aviation fuel production, high temperature industrial process heating, heavy-duty long-haul transportation, and maritime shipping.

III. GHG Emission Reductions Achievable Through Hydrogen Co-Firing

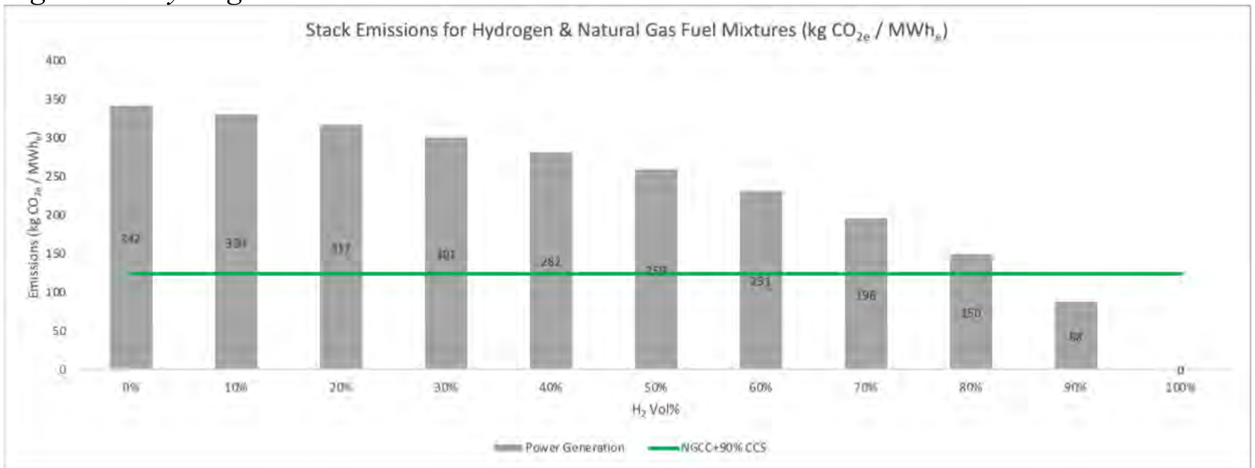
The relationship between the volume of hydrogen co-fired and the emissions reduction achievable is not linear as shown in the chart below; meaningful emissions reductions do not occur except at high hydrogen blend rates. When considering the full lifecycle GHG emissions impact of hydrogen production, this significantly limits the ability of hydrogen blending to reduce emissions. Figure 26 shows the potential emissions reductions of hydrogen blends, compared to 90 percent CCS (the green line).

Figure 26. Hydrogen and Natural Gas Blend Emissions – Full Lifecycle



To compare emissions scenarios for hydrogen blends and CCS only at the stack, the emissions from hydrogen production and the upstream natural gas emissions can be removed. This comparison is shown in Figure 27.

Figure 27. Hydrogen and Natural Gas Blend Emissions at the Stack



A. Accounting for Upstream Emissions When Calculating Emissions Reductions

Upstream methane emissions for the natural gas used to blend with hydrogen in co-firing play a significant role in determining whether hydrogen blending ratios meet target emission thresholds, as shown in table 12 below. Thus, EPA's calculation of emissions reductions from hydrogen co-firing depends on its inclusion of upstream methane emissions from the natural gas blended with the hydrogen. If EPA does not account for these emissions, it will not have an accurate accounting of actual GHG emissions reductions from hydrogen co-firing.

Table 12. Upstream methane emissions from natural gas used to blend with hydrogen[603]

Sensitivity Case	A	B	C	E	F	G
H_2 Carbon Intensity (kg CO_2e/kgH_2)	0.00	0.00	0.00	0.45	0.45	0.45
Upstream Methane Emissions	2.30%	1.00%	0.20%	2.30%	1.00%	0.20%
0% Blending Emissions (lb CO_2e/MWhe)	1038	942	882	1038	942	882
30% Blending Emissions (lb CO_2e/MWhe)	913	828	776	919	834	781
96% Blending Emissions (lb CO_2e/MWhe)	120	109	102	161	150	143

As shown in the table above, variations in upstream methane emissions significantly change the resulting emissions of the turbine. Assumptions for these calculations are listed in Table 13, below. Between case A, B, and C, varying the upstream methane leak rate from 0.20 percent to 2.00 percent can change the resultant emissions from co-firing 30 percent hydrogen in the turbine by about 130 lb CO_2e/MWhe—around a 10 percent swing between EPA's emission targets. As a result, we encourage EPA to account for upstream methane emissions from natural gas when calculating the emission reductions achieved from hydrogen co-firing.

Additionally, EPA selected 0.45 $kgCO_2e/kgH_2$ as a threshold for low-GHG hydrogen. Hydrogen producers are not incentivized to go lower than the 0.45 $kgCO_2e$/kg H_2 threshold. It is thus vital that EPA uses a conservative estimate for electrolytic hydrogen by using 0.45 $kgCO_2e$/kg H_2 as a benchmark, rather than 0 $kgCO_2e/kgH_2$ emissions, when calculating blending emissions. For additional analysis on the lifecycle emissions associated with hydrogen, see Section VI *infra*.

IV. Hydrogen Co-Firing at Gas-Firing Power Plants May Lead to NOx Emissions but These Emissions Can Be Effectively Managed.

Due to hydrogen's high reactivity and adiabatic flame temperature, its potential to produce high levels of NOx emissions is often raised as an argument for excluding gas turbines that co-fire

[603] Assume that there is no efficiency change between turbines co-firing hydrogen and turbines firing natural gas. Hydrogen turbines are likely to be less efficient, or have higher rates, which would further reduce the emissions abatement and increase the costs of implementing hydrogen co-firing. Methane GWP was evaluated at 30 on a GWP 100 basis.

hydrogen as a decarbonization tool. Thus, while hydrogen co-firing as a compliance option to decrease CO_2 emissions from natural gas plants is technically viable, it is important to consider what NOx limits turbines must abide by. These include NOx challenges with burning hydrogen, the current state of NOx management in turbine technology, and how turbine OEMs are actively working to mitigate these concerns.

First, current federal New Source Performance Standards (NSPS) limit NOx emissions from new natural gas turbines to 15 ppm for turbines larger than 250 MW capacity and 25 ppm for turbines smaller than 250 MW. However, these criteria should be viewed as minimum performance requirements that are often lowered in a facility permitting process. In general, permitted gas turbine combined cycle plants can achieve NOx emissions below 9 ppm (at 15 percent oxygen) without post-combustion treatment.

Regarding NOx challenges when burning hydrogen, it is important to recognize that firing gas turbines with hydrogen above small levels presents challenges for NOx emission management, which varies with the level of hydrogen in turbine fuel. Since hydrogen will affect a variety of gas turbine systems—including the combustor and hot gas path as well as fuel management and control strategies—NOx mitigation will have to be achieved in the context of other performance challenges when designing gas turbines to burn hydrogen. With dry low NOx combustors, F-Class combined cycle gas turbines burning natural gas can achieve NOx emissions below 9 ppm by volume (dry basis, adjusted to 15 percent oxygen) and in the low single digits (ppm) with selective catalytic reduction (SCR). Without mitigation, hydrogen combustion has the potential to increase NOx formation due to high adiabatic flame temperatures. However, hydrogen's combustion characteristics (e.g., flammability at low (lean) equivalence ratios) can be exploited to minimize and mitigate NOx emissions.

NOx emissions from gas turbines burning up to 100 percent hydrogen can be managed effectively with diffusion flame combustors. The turbine OEMs have considerable experience with these systems. Diffusion combustors rely on an inert diluent for NOx control (generally either nitrogen gas, or water/steam). Nitrogen availability is limited to IGCC and chemical plants having air separation plants. Steam/water abatement incurs high water consumption and demand on limited resources. Diffusion combustion is a limited option for high-hydrogen turbines.

Turbine manufacturers are adapting natural gas dry low-NOx (DLN) and dry low-emission (DLE) combustor technology to take advantage of hydrogen's beneficial combustion characteristics. With current combustors and increased hydrogen to natural gas ratios, OEMs aim to keep NOx emissions at the same level as their natural gas DLN combustors. The latest versions of these combustors can accommodate fuels with as much as 20–30 percent hydrogen by volume with some OEMs claiming capability to operate on 65 percent hydrogen with advanced combustor designs. While diffusion flame combustors are already 100 percent hydrogen-capable, their performance with respect to emissions of NOx is limited to applications where inert diluent is available. Thus, OEMs are expanding the hydrogen capability of current, premixed dry low NOx combustors while also introducing turbines with new combustor concepts.

By the end of this decade, OEMs are aiming to achieve NOx emissions performance similar to or better than natural gas while firing fuel with high (up to 100 percent) blends of hydrogen. OEMs have the resources, technologies, tools, experience, and qualification processes, as well as the development facilities necessary to solve combustion, thermal management, and materials issues associated with hydrogen and the increased moisture in its combustion products. Backup and startup procedures will likely require 100 percent natural gas, distillate, or other low-reactive fuel, so that a dual-fuel control system and combustor configuration will be necessary as have been employed for synthetic gas/natural gas-fueled IGCC turbines. The key questions are when and how these solutions will be commercially available, and how much operational complexity and restrictions will be necessary.

Projecting forward to a future hydrogen economy when high quantity supply and distribution infrastructure are established, hydrogen can replace natural gas as a primary gas turbine fuel. This would relieve gas turbine designers from having to incorporate complex combustor, fuel control system, and operational design as currently required for firing hydrogen over wide concentration ranges. Simplified combustor designs optimized for single, pure hydrogen fuel will be possible. For example, micromixer technology has been demonstrated at prototypic turbine operating conditions to achieve single digit NOx for fuels having 95 percent to 100 percent hydrogen.[604]

The potential for increases in NOx emissions is of considerable concern particularly for communities already burdened with multiple streams of pollution. While EPA may not have direct authority to regulate other pollutants in this rulemaking, EPA should encourage implementation and compliance that takes the prevention of NOx emission increases and community protection seriously.

V. Costs of Hydrogen Co-Firing at Gas-Fired Power Plants

A. Delivered Cost of Low-GHG Hydrogen

Delivered costs of low-GHG hydrogen are unlikely to fall below \$2/kg including the full 45V production tax credit for most of the United States due to limitations in cheap, low-carbon electricity, making co-firing hydrogen a more expensive emissions reduction technology for most power generation facilities compared to CCS. This limitation is a large driver behind why co-firing low-GHG hydrogen is not the best pollution control technology for baseload gas-fired EGUs. It should, however, remain an available compliance option where the economics make sense, and it should set the standards for intermediate and peaking plants where lower capacity factors make it more difficult to recuperate the capital costs of carbon capture.

The cost of co-firing hydrogen depends on the capital costs for a hydrogen-ready turbine and the variable costs of using low-GHG hydrogen. As noted in the EPRI data cited in the proposal, the capital costs associated with a new hydrogen-ready turbine will likely be around 10 percent more than an equivalent natural gas turbine.

The bulk of the costs for hydrogen co-firing lie in the procurement costs of low-GHG hydrogen and can be split up into production, transport, and storage components. EPA projects that low-GHG hydrogen production costs will to fall to \$0.40/kg by 2030 while the delivered cost to the

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[604] Norm Schilling, *Emissions and Performance Implications of Hydrogen Fuel in Heavy Duty Gas Turbines* 3 (2023), https://cdn.catf.us/wp-content/uploads/2023/07/20174030/emissions-performance-implications-hydrogen-fuel-heavy-duty-gas-turbines.pdf [Attachment 13].

turbine will range from $0.70/kg to $1.15/kg. This projection is highly optimistic and actual costs, per our projections and calculations, for low-GHG hydrogen are unlikely to fall below $5/kg, or $2/kg when subsidized with the 45V production tax credit.

Commenters project production costs to land around $3/kg, or almost free when qualifying for the maximum $3/kg credit in the 45V production tax credit (excluding transport and storage costs), in the long term. There are a few key factors that are likely to drive reductions in production cost:

- **Electricity Price** - The most significant factor is the price of electricity, which can account for 50 percent–75 percent of the overall cost of hydrogen produced via electrolysis and is the main bottleneck for lower hydrogen prices.
- **Electrolyzer load** - Higher electrolyzer capacity factors, which can be increased today, can help recuperate the capital costs of the electrolysis facility. This will depend on the availability of clean electricity and more cost-effective electricity storage options, both of which are becoming more prevalent.
- **Total Installed Cost** - The total installed cost of electrolyzers will progress along the learning curve and decrease over time. Our estimate of the potential reduction in total installed cost is sourced from the 2022 ISPT report[605], which provides the capital cost breakdown for a gigawatt scale plant.
- **Efficiency -** The potential for electrolyzer efficiency improvements by 2030 was estimated by Fraunhofer in a study[606] commissioned by CATF in 2021. These improvements are dependent on sustained electrolyzer demand and rapid progress in research and development.
- **Financing costs** – Building and operating numerous electrolysis facilities will improve developer experience, reduce technology risk, and drive down the cost of capital.

The largest bottleneck to lower hydrogen prices is the lack of cheap widely-available, and firm low-carbon electricity.[607]

For storage, the DOE liftoff report projects that compressed gas storage should be around $0.8 to $1.0/kg while salt caverns would land around $0.05 to $0.15/kg. Given that salt caverns are not ubiquitous throughout the country, $1.0/kg for storage costs is a more likely cost estimate.

For transport, the costs vary depending on the method (e.g., liquid hydrogen, liquid organic hydrogen carriers, tube trailers, pipelines, etc.). Hydrogen co-firing will demand high volumes of hydrogen and will likely require pipelines for transport. We estimate around $1/kg for transport by pipeline.

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[605] ISPT, *A One-GigaWatt Green-Hydrogen Plant*, 30-34 (2022), https://ispt.eu/media/Public-report-gigawatt-advanced-green-electrolyser-design.pdf

[606] Fraunhofer, *Cost Forecast for Low-Temperature Electrolysis*, 73-74, 2021, https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/cost-forecast-for-low-temperature-electrolysis.pdf.

[607] Fossil-based hydrogen with CCS has been excluded from this analysis because it is highly unlikely that it qualifies as low-GHG hydrogen for the purposes of this proposal. Please see the subsequent section on fossil based hydrogen with CCS for more details.

Cumulatively, these costs add up to around \$5/kg, or \$2/kg when subsidized with 45V, for the delivered cost of hydrogen to the power plant.

B. Carbon Abatement Costs from Co-firing Hydrogen

To understand the significance of these different projections in hydrogen prices, it is valuable to compare the cost of carbon abatement, or the cost to abate each ton of carbon, for the two proposed pollution control technologies: CCS and low-GHG hydrogen co-firing.

Figure 28. Carbon abatement costs for co-firing hydrogen in a new combined cycle plant and a new simple cycle plant[608]

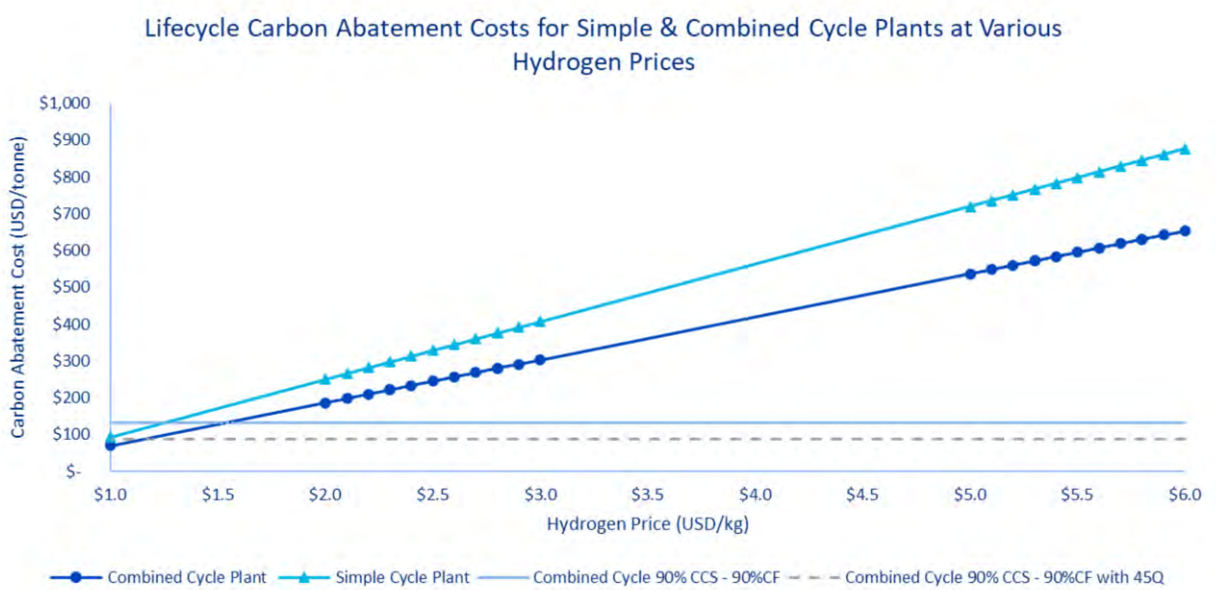

Figure 28 shows the carbon abatement costs for co-firing hydrogen in a new simple cycle plant, and a new combined cycle plant. We used plant operating data from Table 1 in EIA's *Cost and Performance Characteristics of New Generating Technologies* in the *2022 Annual Energy Outlook* and emissions reduction data from Exhibit 5-25 in NETL's *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*. For comparison, the graph also shows the carbon abatement costs with and without the full 45Q credit on a new combined cycle plant with CCS. The 45Q credit was assumed to be \$45/ton for a

[608] CATF's analysis utilizes the following assumptions and sources. Assumed no heat rate changes between a NGCC and a hydrogen based one. A higher heat rate will increase the cost of carbon abatement for hydrogen. No additional CAPEX requirement is assumed for hydrogen operation. Adding CAPEX will increase the carbon abatement costs of co-firing hydrogen. Baseline natural gas price is \$3/MMBTU-HHV. Assumed low-GHG H_2 has a carbon intensity of 0.45 kg CO2e/kg H_2, given that producers are not incentivized to go below 0.45. Upstream methane emissions is 0.99 percent with a 100-year GWP of 30. We assumed upstream CO2 emissions amounted to 0.4 kg CO2e/kg natural gas.

30-year amortization per EPA's *Carbon Capture and Storage for Combustion Turbines Technical Support Document,* Fig. 8, at 11.

For the hydrogen firing plants, there is a linear relationship between the hydrogen price and the carbon abatement cost. This can be described by the following two equations:

- Simple Cycle Abatement costs = 157x - 63
- Combined Cycle Abatement costs = 117x - 47

Using these equations, we can convert the previous hydrogen pricing projections to carbon abatement costs for a combined cycle plant. This results in \$34 to \$87/ton of CO_2 for EPA's projected hydrogen costs of \$0.70 to \$1.15/kg H_2. For a simple cycle plant, this changes to \$47 to \$117/ton CO_2. As a note, this differs from the proposal's carbon abatement costs of \$70/ton of CO_2 for \$1/kg hydrogen and \$35/ton of CO_2 abated for \$0.75/kg hydrogen. While the magnitude of carbon abatement costs is similar between the two calculations, EPA's proposal has the same cost despite different power plant technologies (simple vs. combined cycle). We highly recommend that EPA reevaluate the proposed carbon abatement costs given that it should vary for changes in power plant types.

Our analysis for a new combined cycle plant results in \$187 to \$537/ton CO_2 for hydrogen costs of between \$2 and \$5/kg and \$250/ton CO_2 and \$721/ton CO_2 for a new simple cycle plant with the same costs. For a new combined cycle plant with 90 percent carbon capture, calculated abatement costs are \$87/ton with 45Q and \$132/ton without 45Q. As a note, CCS carbon abatement costs for this analysis are higher than those calculated in Appendix A due to a difference in assumptions.[609] Lower CCS carbon abatement costs will make it an even more competitive emissions reduction technology than co firing hydrogen.

A combined cycle plant with CCS has significantly lower carbon abatement costs should hydrogen prices land around \$2/kg and will still remain competitive when hydrogen is between \$0.70 and \$1.15/kg. Looking at this from another angle, we can also calculate that delivered low-GHG hydrogen must be cheaper than \$0.96/kg of H_2 (\$1.25 if 45Q credits are omitted) for combined cycle plants to undercut CCS as the cheaper carbon abatement option. Even should EPA's highly ambitious projected costs for low-GHG hydrogen costs come true, CCS will likely still be the more economical solution for some combined cycle plants operating at high capacity factors.

EPA's projected delivery price of \$0.70 to \$1.15/kg H_2 also assumes that low-GHG hydrogen receives the max tier of the 45V hydrogen production tax credit at \$3/kg. However, the tax credit is only temporary. 45V will do leaps and bounds for the hydrogen industry by building out the world's electrolyzer manufacturing capacity, fostering expertise in a nascent industry across the value chain, developing the necessary infrastructure, and more. While these changes will help

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[609] EPA uses \$3.69/MMBTU natural gas, 12 year amortization for a \$85/ton tax credit, a 75 percent capacity factor, and \$10/ton TS&M costs. EPA also uses a lower total as spent capital for a new combined cycle power plant with CCS that ranges from \$2115 to \$2329/kW. In comparison, this analysis uses EIA data that results in a total as spent capital of \$3110/kW. EPA's results are also in 2018 dollars while the analysis here is done in 2024 dollars. Meeting the difference between the two will require adjusting for interest rates. This analysis is illustrative and our recommendations for calculating CCS costs are found in Appendix A.

bridge the cost differential between unabated fossil-based hydrogen and low-GHG hydrogen, the credit itself is not a long-term solution to make hydrogen co-firing economically viable—especially when there are other potentially more viable options. The greater fear is that when the tax credit expires, infrastructure has been locked in, built with public funding, for hydrogen co-firing plants that are too expensive to operate due to the lack of cheap hydrogen should the projected production cost reductions fail to materialize.

C. Incremental Levelized Cost of Electricity Comparison

CCS makes more sense than hydrogen in high capacity factor or base load environments. This relationship shifts when capacity factors change as shown in Figure 29.

Figure 29. Incremental levelized cost of electricity (LCOE) for a combined cycle power plant with hydrogen co-firing or CCS applied for emissions reduction[610]

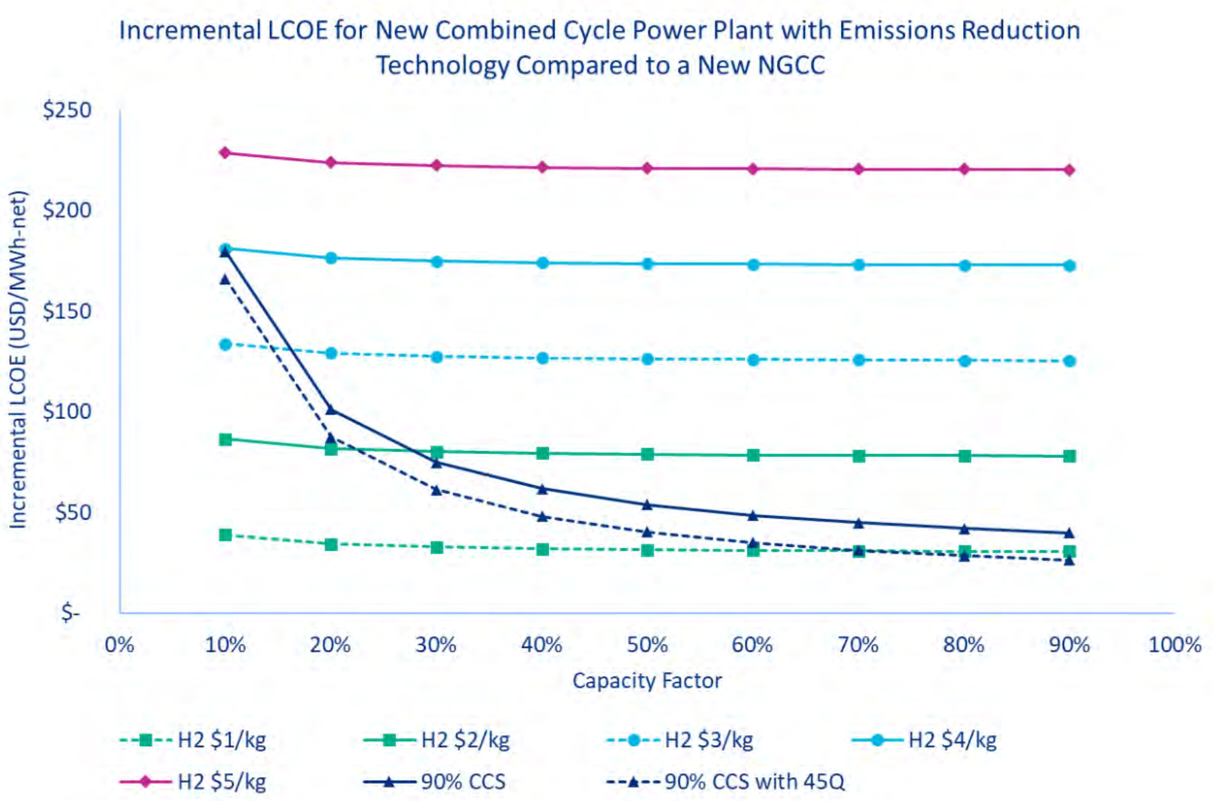

Figure 29 shows the incremental LCOE for using hydrogen and carbon capture across a range of capacity factors for a combined cycle plant. The incremental LCOE was derived by subtracting the LCOE for using natural gas at $3/MMBTU-HHV from the LCOE for using hydrogen co-firing or carbon capture. This provides a comparison of the additional costs for building a plant with either emission reduction technology compared to building a new, unabated NGCC plant.

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[610] The same assumptions used to calculate the carbon abatement cost graph in Figure 28 were applied for this analysis.

We assumed capital, fixed, and non-fuel variable costs for a hydrogen-ready combined cycle power plant were 10 percent higher than a natural gas based equivalent per EPRI's REGEN Model.[611] Actual costs may differ given that these are modeled results. Higher capital, fixed, or non-fuel variable costs will all increase the carbon abatement costs–and thus the incremental LCOE–of co-firing hydrogen. These additional costs for hydrogen co-firing plants were applied to the plant operating data obtained from Table 1 in EIA's *Cost and Performance Characteristics of New Generating Technologies* in the *2022 Annual Energy Outlook*. Plant data for NGCC plants with CCS was from the same table. We assumed there were no heat rate changes between a natural gas based combined cycle plant and a hydrogen based one. We also assumed the full 45Q tax credit is applied at $45/ton for a 30-year amortization per EPA's *Carbon Capture and Storage for Combustion Turbines Technical Support Document,* Fig. 8, at 11.

For carbon capture on NGCC plants, both the incremental LCOE and the carbon abatement cost increase with decreasing capacity factors. The significant capital cost to build a NGCC plant with CCS serves as the main driver behind this relationship because the lower run times makes it more difficult for the utility to recuperate the capital invested. There is a less pronounced version of the same relationship for building a new hydrogen combined cycle plant. While the higher capital, fixed, and non-fuel variable costs for these hydrogen co-firing plants do increase the incremental LCOE, changes in low-GHG hydrogen costs have significantly more influence; higher low-GHG hydrogen costs increase the incremental LCOE for hydrogen co-firing. The higher incremental LCOE for NGCC plants with CCS at lower capacity factors means that co-firing hydrogen may be more economically viable for low-load and intermediate-load power plants.

The exact capacity factor where co-firing low-GHG hydrogen is cheaper than CCS depends on the price of hydrogen. If the delivered cost of low-GHG is $1/kg, hydrogen combined cycle power plants have a lower incremental levelized cost of electricity than carbon capture plants when capacity factors dip below about 60 percent. If the delivered cost of low-GHG is $2/kg, this threshold drops to about 20 percent. At higher hydrogen prices, the incremental LCOE for hydrogen likewise increases, making CCS more attractive. As a note, CCS carbon abatement costs for this analysis are higher than those calculated in the previous section due to a difference in assumptions.[612] Lower CCS carbon abatement costs will make it an even more competitive emissions reduction technology than co firing hydrogen.

Overall, delivered low-GHG hydrogen prices are unlikely to fall below $2/kg in the near future, which will be prohibitively expensive for high capacity factor power plants (>50 percent) to co-fire, making CCS a better option for emissions reduction in comparison. Low-GHG hydrogen has to be cheaper than $0.96/kg, which means that CCS will still be financially competitive even if delivered low-GHG hydrogen prices dip to EPA's ambitious projections of $0.70 to $1.15/kg by 2030. These high cost barriers should exclude it from being considered a BSER technology for baseload gas-fired EGUs. This relationship shifts at lower capacity factors, where the high capital costs of installing CCS significantly increases the incremental LCOE for these plants.

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[611] EPRI, *REGEN Model*, https://us-regen-docs.epri.com/v2021a/assumptions/electricity-generation.html#new-generation-capacity (last visited Aug. 8, 2023).
[612] For these assumptions, see *supra* note 609.

VI. Lifecycle Emissions Associated with Upstream Hydrogen Emissions Could Undermine the Intent of Section 111 if Low-GHG Hydrogen Is Not Required and Properly Defined and Verified

A. EPA must consider relevant impacts from a pollution control that could undermine the best system determination

For subcategories where EPA finalizes hydrogen co-firing as the BSER—which Commenters support for intermediate- and low-loads—EPA must require that only "low-GHG hydrogen" may be blended to ensure meaningful actual reductions of overall GHG emissions. The production method of hydrogen is a key characteristic of the fuel, as "hydrogen typically does not exist freely in nature" and must be produced by separating it from other compounds.[613] The production method of hydrogen, therefore, determines its carbon intensity. EPA can and must specify the type of hydrogen that power plants can blend to ensure that hydrogen used in co-firing does not result in greater overall GHG emissions.

As EPA correctly recognizes, different methods of hydrogen production emit varying levels of GHGs, and hydrogen is "generally characterized by its production method and the attendant level of GHG emissions."[614] Currently, over 95 percent of hydrogen produced is made using steam methane reforming (SMR) without carbon capture, which EPA correctly notes "results in higher overall CO_2 emissions than using the natural gas directly in the EGU."[615] EPA anticipates that by 2032, low-GHG hydrogen will be the most prevalent form of hydrogen available for electricity production.[616] We agree with EPA that incentives from the IRA and IIJA could lead to greater production of clean hydrogen. Even with this projected increase in availability, including a definition of low-GHG hydrogen and requirement that power plants use it will ensure that emissions reductions from the use of hydrogen co-firing are meaningful, do not result in emissions increases elsewhere, and provide the best emissions reductions.

In the final rule, EPA can and must set clear parameters on the type of hydrogen that can be blended for any standards or compliance based on hydrogen co-firing.[617] We support EPA's proposal that where hydrogen co-firing is the BSER, plants must blend "low-GHG hydrogen." We also support EPA's proposed definition of low-GHG hydrogen: hydrogen "produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen (kg CO_2 e/kg H_2) on a well-to-gate basis,"[618] with the caveat that EPA should not rely on the current Greenhouse gases, Regulated Emissions, and Energy use in Transportation model ("GREET model") to determine emissions since it does not yet account for

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[613] NREL, *Hydrogen Basics*, https://www.nrel.gov/research/eds-hydrogen.html#:~:text=Because%20hydrogen%20typically%20does%20not,vapor%20as%20a%20by%2Dproduct (last visited Aug. 7, 2023).

[614] 88 Fed. Reg. at 33315.

[615] 88 Fed. Reg. at 33307. Emissions from co-firing hydrogen produced with SMR and no CCS will always be higher than simply using natural gas directly at the EGU, as it takes energy to transform natural gas into hydrogen.

[616] 88 Fed. Reg. at 33310.

[617] EPA solicits comment on whether a specific definition of low-GHG hydrogen should be included in its final rule. 88 Fed. Reg. at 33304.

[618] 88 Fed. Reg. at 33304, 33310.

indirect grid emissions associated with electrolytic hydrogen production.[619] With rigorous lifecycle analysis GHG accounting, the 0.45 kilogram of CO_2e ceiling limits co-firing to truly clean hydrogen and thus ensures that only hydrogen produced without creating large emissions of GHGs can qualify as the "best" system of emission reduction.

EPA has rightfully proposed that hydrogen that does not itself create large emissions of GHGs through the production process is the "best" system of emission reduction.[620] To determine the "best" system of emission reduction, EPA has the authority to specify the type of fuel that power plants can blend.[621] This includes defining the characteristics of the required fuel, such as its carbon intensity.[622] Critically, in determining what is "best," the Clean Air Act requires EPA to consider other environmental factors and energy impacts of using a fuel,[623] including significant countervailing environmental damage caused by using the fuel.[624] Given the goal of Section 111 of reducing emissions that "cause[ ], or contribute[ ] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare,"[625] measures to reduce emissions cannot be the best system of emission reduction if those measures *increase* emissions of the pollutant being regulated.[626] Such a result would not be "logical and rational."[627] And it would

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[619] *See* Nat. Res. Defense Council & Clean Air Task Force, Joint Comment Letter on Legal Necessity of the Three-Pillars, 3, 5 n.17 (April 10, 2023), https://www.regulations.gov/comment/IRS-2022-0029-0209. We provide a deeper explanation of this caveat in the following sections.
[620] 88 Fed. Reg. at 33310, 33315.
[621] *West Virginia v. EPA*, 142 S. Ct. 2587, 2611 (2022) (noting that "fuel-switching" is a "more traditional air pollution control measure[]").
[622] *See, e.g.*, 80 Fed. Reg. 64510, 64621 (setting standard for non-baseload natural gas-fired combustion turbines by restricting use of fuels with higher CO_2 emission rates).
[623] 42 U.S.C. § 7411(a)(1). *See also Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 441 (D.C. Cir. 1973) (remanding for "further consideration and explanation by the Administrator of the adverse environmental effects" of the proposed BSER).
[624] *See, e.g.*, *Hearth, Patio & Barbecue Ass'n v. EPA*, 11 F.4th 791, 796 (D.C. Cir. 2021) (EPA must consider the "health, environmental, and energy considerations" associated with a proposed BSER); *Portland Cement Ass'n v. E.P.A.*, 665 F.3d 177, 183 (D.C. Cir. 2011) (same); *Essex Chemical Corp.*, 486 F.2d at 433 (holding, even before Congress amended the CAA to expressly require consideration of environmental quality impacts, that a BSER cannot impose "exorbitan[t]" environmental costs); *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 385 (D.C. Cir. 1973) (holding that EPA must consider the "counterproductive environmental effects of a proposed standard" under Section 111, even before Congress expressly added that requirement in 1977); *cf. id.* at n.42 ("The standard of the 'best system' is comprehensive, and we cannot imagine that Congress intended that 'best' could apply to a system which did more damage to water than it prevented to air.); *Sierra Club v. Costle*, 657 F.2d 298, 331 (D.C. Cir. 1981) (In passing the 1977 CAA amendments, "Congress made no attempt to. . . reduce the range of discretion that had been read previously into the 'cost' factor," including costs to the environment).
[625] 42 U.S.C. § 7411(b)(1)(A). *See also National Lime Ass'n v. EPA*, 627 F.2d 416, 426 (D.C. Cir. 1980) ("The purpose [of Section 111] is to assure that new or modified plants will not create significant new air pollution problems."); *National Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 783 (D.C. Cir. 1976) ("the Clean Air Act, and section 111 in particular, was . . . designed to prevent new pollution problems").
[626] *See Essex Chemical Corp.*, 486 F.2d at 439 (In setting BSER for plants, EPA failed to consider fact that use of a sodium sulfite-bisulfite scrubber produced "nearly twenty tons of the purge waste in only one day of operation," even though it would "effectively cut air emissions"). *Cf. Michigan v. EPA*, 576 U.S. 743, 752 (2015) ("No regulation is 'appropriate' if it does significantly more harm than good.").
[627] *Michigan*, 576 U.S. at 750. *See also id.* ("Federal administrative agencies are required to engage in 'reasoned decision making.'").

conflict with the express purpose of the Clean Air Act: to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare."[628]

Finally, the IRA requires EPA to "ensure" reductions in GHG emissions that "result from changes in domestic electricity generation and use," relative to a business-as-usual baseline through 2031.[629] But if EPA fails to consider the energy inputs for electrolytic hydrogen—and thereby permits power plants to comply with Section 111 regulations by co-firing dirty hydrogen—then emissions related to electricity generation could vastly exceed the business-as-usual baseline. This outcome would defy Congress' clear instructions.

In establishing hydrogen co-firing as the BSER for certain subcategories, EPA must consider the environmental impacts of blending different types of hydrogen and must base this determination on the type of hydrogen that does not cause overall GHG emissions increases. In Section F, *infra*, we outline the requirements that EPA should establish on the type of hydrogen plants can blend.

B. Guidelines for electrolytic hydrogen

Once more, we agree with EPA's proposed definition of low-GHG hydrogen as hydrogen with a lifecycle emissions rate of 0.45 kg CO_2e/kg H_2 (with the same added caveat regarding the proposed use of the GREET model). As EPA points out, electrolysis can produce sufficiently low-GHG hydrogen by splitting water molecules, rather than petrochemical molecules.[630] But electrolysis is an energy-intensive process.[631] For example, if a hydrogen electrolyzer draws on fossil energy (or diverts existing clean energy from the power grid), then lifecycle emissions for electrolytic hydrogen will skyrocket. Indeed, several analyses have concluded that electrolytic hydrogen produced with grid-average electricity could have an average annual carbon intensity of 20 kg CO_2e/kg H_2—almost twice the carbon intensity of hydrogen derived from traditional steam methane reformation.[632]

Therefore, without appropriate guidelines, a hydrogen co-firing BSER could paradoxically *increase* GHG emissions. The emission intensity of the energy inputs for electrolysis would dwarf any emission reduction stemming from co-firing electrolytic hydrogen. This would render the BSER ineffective and counterproductive. We therefore support EPA's attempt to "assur[e] that energy inputs [for hydrogen electrolysis] are consistent with the low-GHG hydrogen standard" of 0.45 kg CO_2e/kg H_2.[633]

[628] 42 U.S.C. § 7401(b)(1).
[629] *See* 42 U.S.C. § 7435(a)(5)-(6).
[630] *See* 88 Fed. Reg. at 33329.
[631] *See* Ulf Bossel & Baldur Eliasson, Alt. Fuels Data Ctr., Dep't of Energy, *Energy and the Hydrogen Economy* 7, https://afdc.energy.gov/files/pdfs/hyd_economy_bossel_eliasson.pdf.
[632] *See, e.g.*, Wilson Ricks et al., *Minimizing emissions from grid-based hydrogen production in the United States*, 18 Env't. Rsch. Letters, at 2 (2023); Tessa Weiss et al., Rocky Mtn. Inst., *Hydrogen Reality Check: All "Clean Hydrogen" is Not Equally Clean* (Oct. 4, 2022), https://rmi.org/all-clean-hydrogen-is-not-equally-clean/; Dan Esposito et al., Energy Innovation, *Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow The Industry* 18-19 (Apr. 2023), https://energyinnovation.org/wp-content/uploads/2023/04/Smart-Design-Of-45V-Hydrogen-Production-Tax-Credit-Will-Reduce-Emissions-And-Grow-The-Industry.pdf.
[633] 88 Fed. Reg. at 33330.

There is an established mechanism for ensuring that energy inputs for electrolysis are consistent with the proposed low-GHG hydrogen standard. Namely, EPA should only recognize hydrogen as "low-GHG hydrogen" when it demonstrates compliance with the three pillars of 1) new clean supply, 2) hourly matching, and 3) geographic deliverability. These criteria will ensure that electrolytic hydrogen falls under the proposed rule's emission threshold of 0.45 kg CO_2e/kg H_2. We explain and explore each pillar in greater depth below.

We agree with EPA that energy attribute certificates (EACs) are useful tools for verifying that energy inputs for electrolytic hydrogen are sufficiently clean to satisfy the proposed rule's definition of low-GHG hydrogen.[634] In the event that hydrogen producers acquire EACs while producing clean hydrogen, we propose that power plants could produce those EACs to demonstrate that co-fired hydrogen complies with the three pillars.

Finally (and crucially), by only recognizing three-pillar compliant hydrogen as "low-GHG hydrogen," EPA can drive emission reductions *without imposing significant economic costs* on power plants. This point is critical. A robust evidence base demonstrates the economic feasibility of the three pillars. The pipeline of three-pillar compliant projects is also growing both in the U.S. and globally. Furthermore, independent models and financial analyses broadly find that—after accounting for federal tax support from the Inflation Reduction Act—low-GHG hydrogen projects consistently pencil out under a three-pillar accounting regime.[635] Because clean hydrogen production will continue apace under three-pillar regulations, power plants will have access to ample supplies of compliant low-GHG hydrogen by the compliance date of 2032.

Pillar 1: New Clean Supply

Under a new clean supply requirement, EACs must reflect new electricity that is not currently on the grid. The rationale for this requirement is simple. Without a new clean supply requirement, electrolyzers will either draw grid-average electricity (which is predominantly fossil-fired energy),[636] or divert existing clean electricity from the grid, driving lifecycle GHG emissions well beyond 0.45 kg CO_2e/kg H_2. According to several analyses, an electrolyzer that draws grid-average electricity will produce hydrogen with a lifecycle GHG footprint of around 20 kg CO_2e/kg H_2 —more than forty times higher than the proposed rule's threshold for low-GHG hydrogen.[637] The same problem emerges when an electrolyzer draws on existing (rather than new) zero-carbon energy. If an electrolyzer diverts existing zero-carbon energy from the grid, then fossil-powered marginal generators will come online to fill the resulting supply gap, driving up overall grid emissions.[638]

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[634] *Id.*

[635] *See* Wilson Ricks & Jesse Jenkins, Princeton University ZERO Lab, *Policy Memo: The Cost of Clean Hydrogen* 1 (Apr. 17, 2023), https://zenodo.org/record/7948769 ("[After] [c]orrecting for [certain] unrealistic assumptions, *all studies agree* that clean hydrogen production meeting robust emissions standards will be cost-competitive in the US from day one, enabling the nascent industry to scale up and contribute to long-term emissions reductions.") (emphasis added).

[636] *See* EIA, *What is U.S. electricity generation by energy source?* (Feb. 2023), https://www.eia.gov/tools/faqs/faq.php?id=427&t=3 (noting that around 60 percent of U.S. electricity generation comes from fossil fuels).

[637] *See, e.g.*, Ricks et al., *supra* note 632, at 5-7; Dan Esposito et al., *supra* note 632.

[638] *See id.*

Power plant operators could demonstrate compliance with a new supply requirement via several pathways. We have also outlined these pathways in a parallel rulemaking involving implementation of the IRA's clean hydrogen production tax credit.[639] To summarize, an EAC will demonstrate compliance with the new supply requirement if it reflects electricity from: 1) A generation project placed into service no more than 36 months before the relevant electrolyzer was placed into service;[640] 2) An uprate to an existing generation project that occurred no more than 36 months before the relevant electrolyzer was placed into service; 3) A marginal generator on the same interconnection node as the electrolyzer (e.g., a generator on the same interconnection node with an hourly LMP below $10/MWh); or 4) A generator that is avoiding retirement as a result of hydrogen-induced demand.

The pathways for complying with the new supply requirement also address EPA's related request for comment on whether the agency should accept EACs representing certain generation scenarios.[641] First, EPA asks if power plant operators may prove the cleanliness of co-fired hydrogen with EACs representing "dedicated low-GHG emitting electricity from a generator sited on the utility side of the meter that is contractually obligated to an electrolyzer."[642] The answer is a qualified yes. It is not enough that the generator is contractually obligated to the electrolyzer (*e.g.*, via a power-purchase agreement). The contract must be for the sale of *new* clean supply. For example, the electrolyzer could agree to a PPA with a generator that has come into service within the prior 36 months, or that has uprated to provide the electrolyzer with additional electricity above a historical baseline.

Second, EPA asks if power plant operators may use EACs representing generation from "a generator co-located with an electrolyzer and sited behind a common utility meter."[643] Again, the answer is a qualified yes. A power plant operator may not use EACs from the co-located generator if those EACs represent electricity that has historically been delivered to the electricity grid, or to some other third party. In other words, the co-located generator must deliver *new* power above its historical baseline to produce a useable EAC for power plant operators. As discussed above, any other approach would encourage co-located behind-the-meter generators to divert clean power from the grid, pushing marginal fossil generators online and increasing overall grid emissions. To demonstrate that they are generating new power, co-located clean energy generators may pursue any of the four compliance pathways outlined above.

Third, EPA asks if power plant operators may use EACs representing "a generator whereby the electrolyzer and generator are co-located but not interconnected to the grid and have no grid exchanges of power."[644] The answer is yes. Because the co-located generator is not connected to the grid (or presumably to any other third party), it is not diverting clean energy from any

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[639] *See* Nat. Res. Defense Council & Clean Air Task Force, Joint Comment Letter on Proposed Implementation of Section 45V Hydrogen Production Tax Credit 7 (June 13, 2023), https://www.regulations.gov/comment/IRS-2022-0029-0218.
[640] This rolling vintage date is consistent with recently approved European regulations under the first Delegated Hydrogen Act. *See* 2023 O.J. (L 157) 16-17.
[641] 88 Fed. Reg. at 33330.
[642] *Id.*
[643] *Id.*
[644] *Id.*

existing use. Therefore, any electricity provided to an electrolyzer will comply with the new supply requirement, and power plant operators may use EACs representing that electricity.

Ultimately, a new clean supply requirement minimizes electrolysis-related emissions, while still allowing robust clean hydrogen industry growth that avoids undue economic costs for power plants.[645] Clean electricity supply increases to match corresponding electricity demand for hydrogen electrolysis. But without new clean supply requirements, hydrogen electrolysis would "unquestionably" raise GHG emissions.[646] The new clean supply requirement is, therefore, critical to "assur[e] that energy inputs [for hydrogen electrolysis] are consistent with the low-GHG hydrogen standard."[647]

Pillar 2: Hourly Matching

EPA should only recognize as "low-GHG" hydrogen that was produced with hourly-matched, new zero-carbon electricity. In other words, if power plant operators use EACs to verify the clean energy inputs for electrolytic hydrogen, then those EACs must reflect new zero-carbon electricity that was produced during the same hour at which the electrolyzer operated. The justification for an hourly-matching requirement is two-fold. First, it is essential for keeping the lifecycle emissions of electrolytic hydrogen below the 0.45 kg CO_2e/kg H_2 threshold in the proposed rule. Second, hourly matching will be feasible well before the compliance date of 2032, with several at-scale providers already operating in the market.

Several analyses prove that hourly matching is critical for measuring and minimizing GHG emissions in the electricity sector. As an initial note, University of California researchers have concluded that under current U.S. grid conditions, annual- and monthly-matching systems broadly "yield[] imprecise emission inventories in most regions and for most end-users."[648] Therefore, "hourly or sub-hourly accounting" is the "best practice for attributional GHG accounting of grid-consumed electricity . . . ."[649] Several analyses that specifically focused on hydrogen production have yielded similar results. Princeton researchers determined that under an annual (or even weekly) matching scheme, electrolysis-related emissions would be almost as high as a scenario in which an electrolyzer simply draws grid-average power.[650] And a Rhodium Group analysis finds that annual matching would increase U.S. GHG emissions by up to 58 MMT in 2030.[651]

Moreover, as EPA correctly acknowledges,[652] the infrastructure required to implement hourly matching is already reaching scale. M-RETS, a nonprofit credit tracking system in North

[645] For further analysis of how three-pillar accounting (including the new supply requirement) will not undermine electrolytic hydrogen growth, *see* Ben Haley & Jeremy Hargreaves, Evolved Energy Research, *45V Hydrogen Production Tax Credits* 4-15, 5-31 (June 2023), https://www.evolved.energy/post/45v-three-pillars-impact-analysis;
[646] Dan Esposito et al., *supra* note 632.
[647] *See* 88 Fed. Reg. at 33330.
[648] Gregory Miller et al., *Hourly accounting of carbon emissions from electricity consumption*, Env't Rsch. Letters., Apr. 8, 2022, at 9, https://iopscience.iop.org/article/10.1088/1748-9326/ac6147/pdf.
[649] *Id.*
[650] Ricks et al., *supra* note 632, at 7-8.
[651] Ben King et al., Rhodium Group, *Scaling Green Hydrogen in a Post-IRA World* (Mar. 16, 2023), https://rhg.com/research/scaling-clean-hydrogen-ira/.
[652] 88 Fed. Reg. at 33331.

America, already has more than 170 million hourly EACs in its system,[653] and it is prepared to provide hourly EACs nationwide.[654] Other organizations—such as EnergyTag—already support hourly matching projects worldwide.[655] Domestic regional organizations are following suit. In response to growing consumer demand, PJM recently announced that it would offer hourly EACs.[656] Meanwhile, the Western Electricity Coordinating Council incorporated the M-RETS platform—and its hourly tracking capabilities—into its web-based tracking system for renewable energy certificates in the Western Interconnection.[657] Given the rapid growth of hourly matching tools, it is unsurprising that energy sector analysts do not view hourly matching as an obstacle to strong domestic growth in electrolytic hydrogen production over the next decade.[658]

Because hourly matching technologies are both sophisticated and scalable, EPA should only recognize hourly-matched hydrogen as "low-GHG" at the onset of the compliance period in 2032. Indeed, at least one major clean energy trade association has conceded that hourly matching technology will be feasible by 2032.[659]

Moreover, hourly matching requirements should apply to both existing and new projects beginning in 2032. Given that hourly matching technologies are available *now*, there is no reason to "grandfather in" projects that come into service before the compliance period. A grandfathering provision would drive considerable GHG emission increases. As noted above, electrolyzers that do not use hourly-matched electricity will produce hydrogen with a lifecycle GHG footprint of up to 10 to 40 kg CO_2e/kg H_2.[660] Therefore, if a significant share of electrolyzers are "grandfathered" into annual (rather than hourly) accounting, overall GHG emissions will spike.

Finally, EPA has also requested comment on the suitability of different systems for hourly attribute tracking, with an eye toward establishing a uniform national standard.[661] There is currently no nationwide standard for hourly, monthly, or annual EAC tracking, which means that establishing a national standard will be required regardless of the granularity of tracking. However, hourly tracking can adopt the EnergyTag standard, which is an accepted industry standard that U.S. voluntary markets already use and could provide a template for a uniform

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[653] Pete Budden, NRDC, *IRA Clean Hydrogen Tax Credit: Debunking Five Myths* (Apr. 24, 2023), https://www.nrdc.org/bio/pete-budden/ira-clean-hydrogen-tax-credit-debunking-five-myths.
[654] *See* M-RETS, *Hourly Data* (accessed July 10, 2023), https://www.mrets.org/hourlydata/.
[655] *See* EnergyTag, *EnergyTag and granular energy certificates* 3 (Mar. 2023), https://www.energytag.org/wp-content/uploads/2022/03/210830-ET-Whitepaper.pdf.
[656] *PJM EIS to Produce Energy Certificates Hourly* (Feb. 13, 2023), https://insidelines.pjm.com/pjm-eis-to-produce-energy-certificates-hourly/.
[657] M-RETS, *WECC Signs Multi-Year Agreement with M-RETS for Software Services* (Apr. 4, 2022), https://www.mrets.org/wecc-signs-multi-year-agreement-with-m-rets-for-software-services/.
[658] *See* Ben Haley & Jeremy Hargreaves, Evolved Energy Research, *45V Hydrogen Production Tax Credits* 4-15, 5-31 (June 2023), https://www.evolved.energy/post/45v-three-pillars-impact-analysis.
[659] American Clean Power, *ACP Green Hydrogen Framework* 5 (June 2023), https://cleanpower.org/wp-content/uploads/2023/06/ACP_GreenHydrogenFramework_Explanation.pdf. The same proposal still advocates for a grandfathering provision that would exempt any electrolyzer placed into service before 2032 from an hourly matching requirement. To be clear, Commenters strongly disagree with that approach, which would drive considerable GHG emission increases.
[660] Ricks et al., *supra* note 632, at 5.
[661] 88 Fed. Reg. at 33331.

national standard. Indeed, M-RETS has already committed to following the EnergyTag standard, and Commenters would support EPA adopting such a standard.

Pillar 3: Regional Deliverability

The final pillar is regional deliverability. In the proposed rule, EPA requests comment on "the appropriateness of requiring geographic alignment for EACs used in conjunction with energy inputs at the balancing authority level" when the compliance period for hydrogen co-firing-based standards begins in 2032.[662]

EPA's concern with geographic alignment is justified. Imagine, for example, an electrolyzer that draws power in a grid region with low renewable generation. And further imagine that this electrolyzer offsets those emissions by purchasing EACs from a distant grid region with *high* renewable generation. The mismatch problem is obvious. The clean energy projects in the high-renewable grid region (*i.e.*, the projects producing the purchased EACs) are likely displacing *other clean energy projects*, not high-GHG generation such as coal or natural gas. Their avoided emissions are much lower than the avoided emissions of a clean energy project in the low-renewable grid region, which would likely displace high-GHG fossil generation. Therefore, without a geographic alignment requirement, the electrolyzer can "offset" its emissions by purchasing EACs that do not reflect meaningful avoided emissions.[663]

Commenters agree with EPA that geographic alignment requirements are necessary to avoid this mismatch problem. But we do not believe that aligning at the load balancing authority level is appropriate. Instead, compliant EACs should reflect electricity generation that occurred within the same Emissions and Generation Resource Electronic Database (eGrid) subregion as the relevant electrolyzer. Indeed, EPA has stated that it creates eGrid subregions to "most accurately matc[h] the generation and emissions from plants within that subregion."[664] Moreover, EPA already produces emission factors by eGrid subregion,[665] making it easier to model attributed emissions (by subregion) from use of unabated grid electricity.

Nevertheless, we recognize that regional boundaries are imperfect proxies for grid composition and congestion. Therefore, Commenters recommend that an EAC should also be considered in compliance with the deliverability requirement if the locational marginal price (LMP) differential between the electrolyzer's grid node and the new, hourly matched clean generator's grid node does not exceed 10 percent. This would permit procurement of clean power across eGrid boundaries during any hours where LMPs are low enough to demonstrate a lack of interregional congestion. Because RTOs regularly report LMPs, the relevant LMP differentials will be available to project developers and power plant operators.

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[662] *Id.*
[663] *See* Rachel Fakhry, NRDC, *Success of IRA Hydrogen Tax Credit Hinges on IRS and DOE* (Dec. 8, 2022), https://www.nrdc.org/bio/rachel-fakhry/success-ira-hydrogen-tax-credit-hinges-irs-and-doe.
[664] EPA, Clean Air Markets Division, *The Emissions & Generation Resource Integrated Database: eGrid Technical Guide with Year 2021 Data* 23, https://www.epa.gov/system/files/documents/2023-01/eGRID2021_technical_guide.pdf.
[665] *See id.* at 108.

C. Hydrogen Produced from Steam Methane Reforming with Carbon Capture Does Not Qualify as Low-GHG Hydrogen

1. Background on Methane's Global Warming Potential

The importance of reductions of methane pollution cannot be understated, especially the role that such reductions play in attempting to avert the climate crisis. Methane is far more potent as a greenhouse gas than CO_2, especially over shorter time periods. Over a twenty-year timeframe, methane has approximately 83 times the global warming potential of CO_2, and approximately 30 times the CO_2 value over a 100-year timeframe.[666] The IPCC found with "*high confidence*" that "[d]ue to the short lifetime of [methane] in the atmosphere, projected deep reduction of [methane] emissions up until the time of net zero [carbon dioxide] in modeled mitigation pathways effectively reduces peak global warming."[667] Unfortunately, recent trends show that atmospheric methane levels have recently been at their highest-ever recorded levels. Since 2007, atmospheric methane levels have been increasing at an accelerating pace, with the largest yearly rise in methane levels ever recorded occurring in 2020 and 2021 (15 and 18 ppb, respectively).[668] A deep near-term reduction in methane pollution is therefore one of the most important actions to be taken in addressing the climate crisis. In a 2021 report, the United Nations Environment Programme and the Climate and Clean Air Coalition concluded that targeted cuts in methane emissions of about 45 percent (180 metric tons a year) by 2030 are considered necessary to meet the 1.5 degrees celsius climate limit and would "avoid nearly 0.3°C of global warming by the 2040s."[669]

2. Hydrogen Produced from Steam Methane Reforming with Carbon Capture Does Not Qualify as Low-GHG Hydrogen

Natural gas-based hydrogen production with high levels of CCS (colloquially known as "blue hydrogen") can help reduce emissions in the near term by rapidly scaling to meet the demand for hydrogen with a lower greenhouse gas footprint. EPA's proposal assumes that this type of hydrogen could qualify as low-GHG hydrogen (well to gate carbon intensity <0.45 kg CO_2e/kg H_2).[670] However, it is highly unlikely to qualify given the need to significantly reduce emissions

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[666] Masson-Delmotte et al., Intergovernmental Panel on Climate Change, Summary for Policymakers *in Climate Change 2022: Mitigation of Climate Change: Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change,* 7-125 (2022), https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_FullReport.pdf.

[667] *Id*. at 24, C.2.3.

[668] World Meteorological Organization, *More bad news for the planet: greenhouse gas levels hit new highs*, Press Release Number: 26102022 (Oct. 26, 2022), https://public.wmo.int/en/media/press-release/more-bad-news-planet-greenhouse-gas-levels-hit-new-highs#:~:text=Since%202007%2C%20globally%2Daveraged%20atmospheric,systematic%20record%20began%20in%201983.

[669] United Nations Environment Programme and Climate and Clean Air Coalition, Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions 89 (2021); *see also* Sun et al., Path to net zero is critical to climate outcome, 11 Sci. Rep. 22173 (2021), https://www.nature.com/articles/s41598-021-01639-y ("[D]ifferent pathways of carbon dioxide and methane . . . can lead to nearly 0.4 °C of warming difference in midcentury and potential overshoot of the 2°C target, even if they technically reach global net zero greenhouse gas emissions in 2050.").

[670] *See* 88 Fed. Reg. at 33329.

associated with upstream methane and upstream CO_2, rates of carbon capture, and the electricity used for hydrogen production and CCS.

Upstream emissions play a large role in this equation and can largely be broken down into two categories: upstream methane emissions and upstream CO_2 emissions.

The rate of upstream methane emissions can vary depending on the method of measurement, the location, and the operator. There is a significant difference between bottom up estimates and top down estimates for fugitive methane emissions. A recent comprehensive study, based on direct emissions measurements from thousands of sites, estimated a 2.3 percent leak rate from U.S. oil and gas operations.[671] This likely underestimates the U.S. leak rate because the study did not include measurements from the Permian basin, which is known to have very high emissions. In addition, methane emissions clearly and substantially vary between production regions. Measured emissions are as low as 0.4 to 0.75 percent for some high-productivity regions in Pennsylvania, and as high as 9.6 percent and 5.7 percent in the Permian and Uinta basins, respectively.[672] Stakeholders must account for the fact that natural gas coming from different production basins, operators, and transportation pathways will have different amounts of upstream emissions. Because utilities are purchasing large quantities of gas and will likely contract with producers (or midstream companies), utilities should demand that the vendor implement a measurement and verification program to quantify the upstream footprint of the gas. Sufficient large utilities requiring low leak rates could be a strong incentive to encourage upstream companies to measure and reduce emissions.

Given that monitoring protocols may not be finalized as part of this rulemaking, Commenters believe that EPA should be conservative in its estimates of leak rates given the significant difference in the carbon intensity of the resultant hydrogen. An appropriate default leak rate is 2.3 percent based on top down estimates. EGUs may also use basin-specific data should it be available.

Upstream CO_2 emissions in this case include all CO_2 released in the exploration, production, processing, and transportation of natural gas. This can vary significantly based on a multitude of factors including pipeline distances and flaring practices. Based on average fuel use and flaring at upstream and midstream in official U.S. reports, CATF calculated an emission intensity of 7.72 g CO_2e for each MJ of natural gas delivered.

To better understand the impact of upstream emissions, capture percentage, and process electricity on the well-to-gate carbon intensity of fossil-based hydrogen, Commenters present a few sensitivity cases in Table 13.

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[671] Ramon Alvarez et al., *Assessment of methane emissions from the U.S. oil and gas supply chain*, 361 Science 186 (2018), https://www.science.org/doi/10.1126/science.aar7204.

[672] *See* Zachary R. Barkley et al., *Quantifying methane emissions from natural gas production*, 17 Atmos. Chem. Phys. 13941 (2017); Yuanlei Chen et al., *Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey,* 56 Env't. Sci. Tech. 4317 (2022); Evan Sherwin et al., *Quantifying oil and natural gas system emissions using one million aerial site measurements* 1-29 (2023), https://dx.doi.org/10.21203/rs.3.rs-2406848/v1.

Table 13. Well-to-gate life cycle analysis sensitivity cases based on CATF analysis

Sensitivity Case	A	B	C
Technology	ATR	ATR	ATR
Capture Rate	95%	98%	98%
Upstream GHG intensity w/o CH4 (g CO_2e/MJ gas)	7.72	0.77	0.77
Upstream Methane Emissions	2.3%	0.09%	0.2%
Electricity Source	U.S. Grid Avg.	Wind	Wind
CCS emissions (kg CO_2e / kg H_2)	0.42	0.06	0.06
CO_2 from gas reformation (kg CO_2e / kg H_2)	0.42	0.17	0.17
Upstream Methane Emissions (kg CO_2e / kg H_2)	2.15	0.08	0.19
Upstream CO Emissions (kg CO_2e / kg H_2)	1.19	0.12	0.12
Process electricity (kg CO_2e / kg H_2)	0.71	0.02	0.02
Total (kg CO_2e / kg H_2)	4.89	0.45	0.55

Emission intensities for the U.S. grid are based on EPA's eGRID database.

Case A showcases the carbon intensity of an ATR with 95 percent CCS that uses grid electricity and the aforementioned averages for upstream emissions. The resulting carbon intensity of 4.89 kg CO_2e/kg H_2 is significantly higher than the 0.45 kg CO_2e/kg H_2 threshold needed to qualify as low-GHG. All emission reduction improvements are necessary and an example of such is shown in Case B. There, the upstream CO_2 is reduced by 90 percent to 0.77 g CO_2e/MJ and the upstream methane emissions are likewise reduced to 0.09 percent. Carbon capture rates are increased to 98 percent, which matches the capture rate at the ExxonMobil hydrogen production facility EPA references in its hydrogen TSD.[673] The electricity, which feeds the ATR and the CCS plant, is swapped to wind power as well. All these measures are easier said than done and are significant departures from today's averages. The combined result is a carbon intensity of 0.45 kg CO_2e/kg H_2. Even then, the fossil-based hydrogen is at the threshold. Case C shows the impact of increasing upstream methane emissions to 0.2 percent, resulting in a carbon intensity of 0.55 kg CO_2e/kg H_2 that disqualifies it from being considered low-GHG. Other deviations like inconsistent monitoring of outage rates and times can likewise skew the carbon intensity.

[673] *See Hydrogen TSD* at 16.

From an energy efficiency perspective, natural gas should instead be burned directly in power plants with CCS. Co-firing fossil-based hydrogen with CCS is less efficient than directly combusting natural gas. Natural gas turbines with 90 percent CCS have an efficiency of around 48 percent.[674] This means that for every 100 MMBTU of natural gas combusted in a NGCC plant with 90 percent CCS, around 52 MMBTU is converted into electricity. Reforming hydrogen in a SMR with 90 percent CCS has an efficiency of around 73 percent, and a NGCC plant without CCS has an efficiency of around 54 percent.[675] Combined, they have an efficiency of 39.0 percent; for every 100 MMBTU of natural gas used to make hydrogen, only 39 MMBTU is converted into electricity at the hydrogen turbine. This is generous considering that it assumes the hydrogen facility is located next to the power plant, allowing us to ignore the transportation and storage inefficiencies of hydrogen. These additional inefficiencies should be avoided if possible, considering that it will likely result in a higher levelized cost of electricity for the consumer.

D. Verification of Low-GHG Hydrogen

EPA should consider the following measures to ensure low-GHG hydrogen is used for compliance:

Thorough recordkeeping and reporting of the lifecycle analysis (LCA) for hydrogen used in co-firing is essential from production through end use regardless of production pathway. EGUs that procure low-GHG hydrogen from producers should still be required to follow the same Greenhouse Gas Reporting Program (GHGRP) reporting requirements. Hydrogen producers that fall under 40 C.F.R. § 98.2(a)(1) or (a)(2) of the GHGRP will already have to report CO_2 emissions for each hydrogen production unit. They likewise must report "CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than the hydrogen production process unit." These emissions can be calculated using a monthly mass and energy balance and/or a continuous emissions monitoring system (CEMS). Taxpayers that produce, process, and/or distribute petroleum and natural gas who satisfy 40 C.F.R. § 98.2(a) must also report their GHG emissions. Commenters recommend that EPA, given its role as an emissions regulation agency and experience with the facilities reporting GHG emissions under the GHGRP, potentially streamline these reporting processes using their existing knowledge and expertise.

Co-firing hydrogen on its own is not enough to prove meaningful emissions reduction from an EGU without further monitoring and verification of the carbon intensity of the hydrogen consumed. Therefore, specific technologies and methodologies for the monitoring of lifecycle GHG emissions for the production and transport of low-GHG hydrogen all the way to the combustion turbine inlet are necessary to ensure climate mitigation has been achieved. LCA associated with low-GHG hydrogen must be verified by a third party in order for the low-GHG hydrogen to meet the eligibility requirements for emission reduction via co-firing. This is an international best practice for credible GHG monitoring under ISO 14064. To facilitate this

[674] EIA, *Cost and Performance Characteristics of New Generating Technologies* in *Annual Energy Outlook 2022* (2022), Table 1, https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.
[675] IEAGHG, *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS* (2017), Table 2, https://ieaghg.org/component/content/article/49-publications/technical-reports/784-2017-02-smr-based-h2-plant-with-ccs.

process, EPA could help create a list of independent verifiers or verification bodies similar to what CARB has created for the California LCFS.

1. Recordkeeping and Disclosure Requirements

Detailed record keeping and verification should be required to ensure truly low-GHG hydrogen is being delivered to and co-fired at the EGU. To demonstrate compliance with the requirement to combust only low-GHG hydrogen, the combustion turbine owner/operator must ask the relevant hydrogen producer for the producer's calculations of GHG levels associated with the hydrogen production. In addition, EGUs should be required to make fully transparent their sources of low-GHG hydrogen and the corresponding quantities procured. This can be demonstrated through purchase agreements and purchasing data (invoices, etc.).

EGUs should be required to disclose with full transparency their sources, quantities, production pathway, and carbon intensity of low-GHG hydrogen procured. Documentation can be demonstrated through purchase agreements and purchasing data including but not limited to invoices, delivery receipts, and associated flow data. Price data need not be included in documentation disclosure. Documentation should be made available on EPA's website and either via the EPA's FLIGHT Tool or a state-run website per state implementation.

If an EGU owner/operator decides to produce low-GHG hydrogen on or adjacent to the EGU property, facilities should be required to install high accuracy billing meters to draw artificial boundaries between their hydrogen production and use in co-firing. There should be standardized guidelines regarding the accuracy of these meters along with an established calibration schedule. EGUs with this setup should submit specification sheets for the billing meter along with the flow data and calibration records when filing documentation with the EPA or state entity. Mass balances should not be a substitute for billing meters, but rather a supplement to mass flow data, given the need for high accuracy measurements.

EGUs will be able to purchase low-GHG hydrogen from hydrogen producers that produce both compliant and non-compliant hydrogen. In this case, the EGU must be able to verify that they purchased low-GHG hydrogen from the producer.

Commenters recommend that, to the extent that plants can operate in different production modes that each produce hydrogen of a specific carbon intensity, plants provide documentation for each production method when filing (i.e., one LCA documentation for the first mode, a second LCA documentation for the second mode, etc.). We recommend that plants indicate the onstream percentage of these different production modes during their application, which would apply even if the different carbon intensities fall under the same GHG-intensity range.

2. Further Considerations for Fossil-Based Low-GHG Hydrogen and GHG Impact of Fugitive Hydrogen Emissions

With respect to hydrogen leak detection, it is important to acknowledge hydrogen's indirect climate impact. At the same time, it is important to keep in mind and compare those indirect impacts with the impacts of the carbon-intensive processes that hydrogen will replace.
In that context, understanding that hydrogen's efficacy as a climate solution can be reduced by leaks underscores the importance of establishing robust leak detection and prevention programs. Combating leaks during the design phase for greenfield projects could make this issue easier to

address. To better assess the risk of hydrogen's indirect warming impact, there must be more robust real-world emissions data across the supply chain and on the efficacy of leak detection programs. Current available emission data mainly consists of estimates regarding leak percentages. Given that there are many ways to produce, transport, and use hydrogen, it is important to assess these emission rates across each permutation. Emissions data should include leaks; venting from start-up, shutdown, and maintenance; and hydrogen-slip from incomplete combustion or reaction. Regarding leak detection methods, a report from Columbia's School of International and Public Affairs detailed the existing detection, monitoring, and prevention technologies.[676] While the report concludes that most technologies still require significant research and development—a conclusion Commenters agree with—it would also be valuable to understand what emission rates could be achieved with a robust hydrogen leak detection program built out of existing mitigation solutions. These solutions could include not only hydrogen detection technologies such as Nitto's hydrogen detection tape[677] used by NASA, but also leak detection technologies available for gas-based operations as a whole.

VII. Severability of the Low-GHG Hydrogen Requirement

EPA requests comment on "whether the low-GHG hydrogen requirement could be treated as severable from the remainder of the standard such that the standard could function without this requirement."[678] The low-GHG hydrogen requirement should not be treated as severable such that co-firing any "hydrogen" would be the best system of emission reduction and serve as the basis of standards. Similarly, EPA should make clear that hydrogen other than low-GHG hydrogen is not available for compliance.

At a more general level, any decision to require low-GHG hydrogen for specific subcategories and phases in which hydrogen is determined to be the BSER operates entirely independently of all other aspects of the proposal. That is to say, any standards or guidelines based on low-GHG hydrogen are severable from subcategories and phases that do not have hydrogen as the BSER.[679]

VIII. EPA Should Separately Initiate a Rulemaking to List and Set Performance Standards for Fossil-Fuel-Based Hydrogen Production Facilities

As discussed in this section, some methods of hydrogen production rely on fossil fuels as a feedstock and emit GHGs. Examples of fossil-fuel-based production processes include coal gasification, as well as ATR and SMR, with or without CCS. To limit GHG emissions from these sources, Commenters urge EPA to list hydrogen production as a source category that causes and contributes significantly to air pollution which is reasonably anticipated to endanger public health or welfare under Section 111(b)(1)(A). The agency should then set emission

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676 Zhiyuan Fan et al., *Hydrogen Leakage: A Potential Risk for the Hydrogen Economy* 8-11 (2022), https://www.energypolicy.columbia.edu/wp-content/uploads/2022/07/HydrogenLeakageRegulations_CGEP_Commentary_063022.pdf.

677 *See* Nitto, DX-2106H Hydrogen Detection Leak Tape Product Data Sheet (January 2021), https://nittodetectiontape.com/products/pc/catalog/NA_DX_2106H_EN0225.pdf.

678 88 Fed. Reg. at 33316.

679 *See Belmont Mun. Light Dep't v. FERC*, 38 F.4th 173, 188 (D.C. Cir. 2022) (explaining portions of rules are severable where "they operate entirely independently of one another"); 88 Fed. Reg. at 33248 (proposing that each of the actions in the proposed rule "function independently and are therefore severable").

standards and emission guidelines for GHGs from new and existing hydrogen production facilities. Any such standards would require a separate rulemaking; however, setting standards for these sources would complement the hydrogen-based best system determination in this proposal.

Appendix C - IPM Model Assumptions For NRDC Reference Case

Key Assumptions Assumption	NRDC 2023 Reference Case
Run Years	
Run Years	2025, 2028, 2030, 2032, 2035, 2038, 2040, 2045, 2050
Model Regions	
Model Regions	ICF
Electric Demand	AEO2023
Peak Demand	AEO2023
Planning Reserve Margin	ICF
Inter-Region Transmission	EPA v6 Post-IRA 2022
Transmission Builds (Endogenous)	EPA v6 Post-IRA 2022
Existing Generators	
Unit-Level Heat Rates	EPA NEEDS v6 02-14-23
FOM and VOM	EPA v6 Post-IRA 2022; NRDC Nuclear FOM
Availability	EPA v6 Post-IRA 2022
Capacity Factors - Existing Hydro	EPA v6 Post-IRA 2022
Capacity Factors - Fossil	EPA v6 Post-IRA 2022
SO_2 Permit Rates	EPA NEEDS v6 02-14-23
SO_2, Hg and HCl ERFs; NOx Rates	EPA NEEDS v6 02-14-23
Life Extension Cost	EPA v6 Pre-IRA 2022; NRDC Nuclear
Renewable Generation Profiles (existing units)	ICF (based on NREL SAM)
New Generators	
Capacity Build Costs - Conventional	AEO 2023
Emission Rates	EPA v6 Post-IRA 2022
Build Structure - Renewables	EPA v6 Post-IRA 2022
Capacity Build Costs - Renewable (non-wind,non-solar)	EPA v6 Post-IRA 2022
Capacity Build Costs - Wind and Solar	NREL 2022 ATB (Mid); Low for Offshore
Capacity Build Costs - Storage	NREL ATB 2022 (Mid); 4/8/10 hr duration
Capacity Build Costs - Solar+ Storage	NREL 2022 ATB (Mid)
Capital Cost Step Adders	EPA v6 Post-IRA 2022
Renewable Reserve Margin Contribution	ICF
Storage Reserve Margin Contribution	ICF
Wind and Solar Generation Profiles (New units)	EPA v6 Post-IRA 2022
Nuclear Builds	Nuclear build option based on AEO's Nuclear—small modular reactor
Pollution Controls	
Pollution Control Retrofits for existing units (SO_2, NOx, HCl, Hg)	EPA v6 Post-IRA 2022

Key Assumptions Assumption	NRDC 2023 Reference Case
CCS Retrofit cost and performance - Coal	EPA v6 Post-IRA 2022
CCS Retrofit cost and performance - New Gas (90% CCS)	AEO 2023
CCS Retrofit cost and performance - Existing Gas (90% CCS)	EPA v6 Post-IRA 2022
CCS Retrofit cost and performance - Other capture rates (100%, or lower than 90%)	NRDC assumption for 99% capture option
CCS Transportation and Storage Curves	EPA v6 Post-IRA 2022
CCS Incentives	45Q based on IRA
Other Existing Unit Modifications	
Coal to Gas Conversions	EPA v6 Post-IRA 2022
Coal to Gas Conversions Laterals	EPA v6 Post-IRA 2022
Heat Rate Improvements	EPA v6 Post-IRA 2022
Financing	
Financing	ICF
Firm Decisions	
Firm capacity additions	Latest ICF and NRDC input as of April 2023
Firm retirements	Latest ICF and NRDC input as of April 2023
Firm pollution controls and coal to gas conversions	Latest ICF and NRDC input as of April 2023
Nuclear	
Nuclear Retirements	1) 80 year lifetime for nuclear 2) endogenous retirements allowed for nuclear units
Nuclear Retirement Limits	1) No economic retirements allowed through 2025. 2) 4GW economic retirements allowed through 2028 3) Retirement limit on Regulated nuclear: No economic retirement before 60 years
Nuclear FOM Adjustment	No inclusion of FOM reduction
Fuel	
Coal Supply/Prices	EPA v6 Post-IRA 2022
Gas Supply/Prices	ICF GMM Q1 2023
Gas Basis and Seasonality	ICF GMM Q1 2023
Hydrogen	Fixed hydrogen price ($3 subsidized in 2023 dropping to $2 subsidized in 2035)
Biomass Supply Prices	EPA v6 Post-IRA 2022
Uranium Prices	AEO 2023
Fuel Oil Price	AEO 2023
Fuel Emission Contents	EPA v6 Post-IRA 2022
Biomass co-firing at coal facilities	EPA v6 Post-IRA 2022

Key Assumptions Assumption	NRDC 2023 Reference Case
Gas co-firing at coal facilities	EPA v6 Post-IRA 2022
Environmental Regulations	
Federal and Air Regulations	EPA v6 Post-IRA 2022, ICF, NRDC
State Regulations	EPA v6 Post-IRA 2022, ICF, NRDC
RPS/CES- Requirements Modeled	Latest ICF and NRDC input as of April 2023
Energy Efficiency	
EE Supply Curves	3 supply curve steps per region with utility program costs in line with NRDC 2017 analysis
EE penetration	Based on NRDC analysis. No incremental EE modeled.
Other	
Reporting $	2022$
Retail Price Model (RPM)	EPA v6 Post-IRA 2022
IRA- Energy Community Tax Credit Increment	Include EPA Energy Community Treatment

I.

II. Model Run Year Mapping

Model Run Year	Calendar Year
2025	2025, 2026
2028	2027, 2028, 2029
2030	2030, 2031
2032	2032, 2033, 2034
2035	2035, 2036, 2037
2038	2038, 2039
2040	2040, 2041, 2042
2045	2043, 2044, 2045, 2046, 2047
2050	2048, 2049, 2050, 2051, 2052

III. High Demand Case Methodology

The High Demand Sensitivity is meant to account for a potential scenario in which electricity demand exceeds current projections under AEO 2023. To estimate one possible future, Commenters estimated potential incremental demand under adoption of EPA's Proposed Light and Medium Duty Vehicle Emissions Standards (L/MDV Proposal) and Heavy Duty Vehicle Emissions Standards (HDV Proposal).

First, we determined the amount of electrification assumed in the AEO 2023 baseline. Total annual electricity consumption of battery electric vehicles was summed across all included vehicle types (light duty vehicles, light commercial trucks, buses, and heavy duty vehicles). Total economy-wide electricity consumption was also referenced to estimate the incremental electricity demand resulting from EPA proposals (described below).

Then, to calculate potential incremental demand from light- and medium-duty vehicles (L/MDV), battery electric vehicle adoption rates for L/MDVs (as calculated by EPA, via OMEGA modeling, for EPA's No Action and Proposed cases in the L/MDV Proposal) were incorporated into a modified EPA MOVES model (MOVES3.R3, an updated version of the MOVES model used to inform/develop EPA's proposed L/MDV emissions standards) to estimate the annual on-road population and vehicle-miles traveled (VMT) of sedans, light trucks, and medium-duty vehicles (i.e., class 2b-3 trucks specific to EPA's MDV definition). These vehicle type-specific VMT values were then combined with corresponding battery electricity consumption rates (kWh per mile) to estimate total electricity consumption of L/MDVs. These kWh per mile factors reflect generic rates and were informed by EIA assumptions and other sources.

Battery electric vehicle adoption rates for HDVs (as calculated by EPA, via HD TRUCS modeling, for No Action and Proposed cases of proposal) were incorporated into a modified EPA MOVES model (MOVES3.R3, used to inform/develop EPA's proposed HDV Phase 3 standards) to estimate the annual on-road population and VMT of different classes of HDVs (and select class 2b-3, or "incomplete," vehicles). These vehicle type-specific VMT values were then combined with corresponding battery electricity consumption rates (kWh per mile, as provided by HD TRUCS) to estimate total electricity consumption of HDVs.

Finally, EIA AEO 2023 Reference Case data were first used to estimate the baseline, non-road electricity demand (i.e., total economy-wide electricity consumption less on-road vehicle electricity consumption). On-road vehicle electricity demand estimates resulting from EPA's No Action and Proposed cases (from both the L/MDV Proposal and HDV Proposal) were then added to this baseline to calculate total economy-wide electricity consumption associated with both scenarios. For each scenario, total economy-wide electricity consumption was then compared against that of the EIA AEO 2023 Reference Case to estimate the incremental change in electricity demand due to on-road vehicle electrification resulting from EPA's L/MDV Proposal and HDV Proposal.